discussed above, provides further support to the conclusion that technological innovation will not cause reduced market power prices.

With respect to the transmission grid and SPP's ability to cost-effectively reduce congestion, very different market and industry fundamentals exist. There are already many new technologies entering the market that have substantial potential to limit increase in congestion costs in the future and the introduction of competition in the transmission industry is already stimulating innovation that reduces the cost of transmission facilities. Cost-effective new transmission technologies that can already reduce congestion cost on the existing system but that are adopted only slowly include smart-wire technology, dynamic line ratings, and topology control, as well as a range of non-wires solutions that can defer transmission upgrades, such as battery storage, demand response, or distributed energy resources. It is thus reasonable to assume that the increases in congestion costs documented in the PROMOD simulations between 2024 and 2029—which do not assume any congestion-relieving technologies beyond the SPP-identified upgrades discussed in my direct testimony—will not continue over the entire 30-year life of the Selected Wind Facilities. It was thus reasonable to assume that congestion costs associated with the Selected Wind Facilities would on average remain at approximately the simulated 2029 levels.

More importantly, as discussed above, if congestion costs from the Selected Wind Facilities were in fact to grow beyond 2029 level and were not addressed by SPP adding new transmission, they would cross the point at which constructing a generation tie line between the Wind Facilities and the AEP load zone would become cost-effective. The cost-mitigating effect of the Company's ability to construct a gen-tie protects the customer benefits of the Selected Wind Facilities in that case. TIEC witness Griffey's suggestion that a continuing increase in congestion costs would necessarily reduce customer benefits is thus unreasonable. In fact, the opposite is possible: that the above-discussed innovations and new technologies in the transmission industry will reduce the congestion costs between the Selected Wind Facilities and the AEP load zone to levels below those simulated, which would increase the projects' customer benefits beyond those estimated by the Company.

Q. DO YOU AGREE THAT BY EMPLOYING PROMOD MODELS, THE COMPANY UNDERSTATED THE COST OF CONGESTION?

A. No. The Company has simulated with PROMOD both base and high-congestion cases, which reasonably cover the probable levels of future congestion considering the PROMOD limitations. As I have shown with Figure 1 on page 33 of my direct testimony, the projected congestion levels between Oklahoma wind and the AEP load zone are reasonably consistent with the mid to upper end of historically observed levels. This is reasonable given SPP's ongoing and planned further expansion of the transmission system, which has already reduced congestion in 2018 and 2019 relative to historical levels. While the PROMOD simulations tend to understate congestion, holding all else equal, the projected congestion costs may not be understated given that SPP may further expand the transmission system over time relative to the system modeled. However, as I have also explained in my direct testimony, the fact that PROMOD simulations tend to understate congestion means that there is the *risk* that future congestion levels could be higher than simulated in the base case. However, as shown for the higher congestion levels in the "No-SPP-Upgrades" simulations, the cost increases associated with the higher levels of congestion, if they should happen due to limited SPP transmission grid improvements, can be capped cost-effectively by constructing a generation tie line from the Selected Wind Facilities to Tulsa. As Company witness John Torpey shows in his testimony, even under those circumstances the Company's ownership of the Selected Wind Facilities offers significant customer benefits.

IV. RELIABILITY OF THE COMPANY'S MULTIPLE MODEL APPROACH

Q. MR. CHILES ARGUES ON PAGE 18 OF HIS DIRECT TESTIMONY THAT THE CALCULATION OF CONGESTION COSTS USING THE PROMOD, AURORA, AND PLEXOS MODELS YIELDS A LOW LEVEL OF CONFIDENCE IN THE FINAL CONGESTION ANALYSIS. HOW DOES HE SUPPORT THIS CLAIM?

A. Mr. Chiles claims that by combining the three models, the issues of each model get compounded, but provides little explanation for this claim. The primary concern he notes with the PROMOD portion of the analysis is that "the power flow model in the PROMOD cases is not the same as the power flow model used in the FCITC analysis." SWEPCO witness Mr. Ali addresses this issue in his Rebuttal Testimony. Mr. Chiles' second concern with the PROMOD model is that the Company's Base Case "eliminates new, proposed transmission facilities that are in the current SPP Integrated Transmission Plan."

Q. DO YOU AGREE THAT THE PROMOD BASE CASE ELIMINATES NEW TRANSMISSION FACILITIES?

A. No. Mr. Chiles does not specify which new transmission facilities he believes the Company has omitted. However, I assume that the "current SPP Integrated Transmission Plan" he refers to is SPP's latest 2019 Integrated Transmission Planning Assessment Report, which SPP published on November 6, 2019—nearly a year after the Company began its RFP process and months after the Company's filing. In any case, while the Company may not have modeled the specific transmission upgrades identified in SPP's 2019 Integrated

Transmission Planning Assessment Report (since SPP had not finalized those upgrades at the time), the PROMOD "Base Case" employed in the Company's customer benefits analysis achieved the same result by eliminating the constraints in the PROMOD model that are associated with the SPP-identified 2019 ITP *needs*. As explained on pages 33-34 of my Direct Testimony, the PROMOD "Base Case" assumed that the 2019 ITP needs identified by SPP would be addressed by SPP when it develops and finalizes the 2019 ITP solutions. SPP typically does not approve projects until the need date is closer to the 3-5 year horizon, and therefore it is appropriate to assume the SPP would solve the needs that it identified in the ten year horizon as it undertakes its ongoing planning process.

Q. WITH RESPECT TO THE ASSERTED DEFICIENCY IN THE AURORA ANALYSIS, HOW DO YOU RESPOND TO MR. CHILES' CONCERN THAT WHEN GAS PRICE AND CARBON COST ASSUMPTIONS ARE CHANGED (TO STUDY DIFFERENT SENSITIVITIES), AURORA IGNORES THE IMPACT OF RESULTING DISPATCH CHANGES ON TRANSMISSION FLOWS AND CONGESTION COSTS?

A. I disagree. While Mr. Chiles is correct that AURORA is not set up to simulate transmission constraints or losses within the SPP footprint, PROMOD is the industry standard tool for that. Because AURORA is unable to estimate congestion and loss-related costs that can affect locational prices between different portions of the SPP footprint and wind delivery costs, the AURORA results for SPP Central needed to be combined with PROMOD results for the locational differences.

As explained in my direct testimony, relying on AURORA is advantageous because, unlike SPP's PROMOD models, AURORA is set up for projecting long-term trends of broader regional market prices as it employs a consistent set of market fundamentals assumptions, including different natural gas and coal prices, for the range of long-term wholesale power market and fuel price scenarios. These market fundamentals are used by AEP companies for all their long-term planning purposes. The PROMOD model is not capable of performing these types of analysis over the longer-term because of the complexity of the large numbers of transmission constraints it must monitor along with the analysis of multiple fundamental assumptions.

As explained in my testimony, PROMOD does simulate transmission flow and congestion, considering the dispatch options and costs of all SPP resources. This will yield realistic estimates of congestion costs. Given a certain transmission network and installed generation base in SPP, these congestion and loss-related costs will primarily be a function of the overall level of market prices—which is determined by the dispatch cost of the marginal generating unit. If natural gas prices are higher, for example, not only will overall wholesale power prices be higher, but the cost of supplying losses and redispatching generation to manage congestion within the SPP footprint will be correspondingly higher as well. Since congestion costs are a direct function of the overall market price, it is reasonable to scale the PROMOD-based congestion cost estimates for wind resources to the overall level of market prices from AURORA. Changes in merit order of resource dispatch due to different fundamental forecasts for gas prices or carbon costs that affect wholesale power prices across different AURORA scenarios are already captured in the AURORA simulation results. For example, if for a given hour, under a specific gas price/carbon cost scenario, coal generation were the marginal resource, then the AURORA simulated market price would reflect that and scaling congestion costs based on the AURORA market price would reasonably capture the impact of this merit order on congestion. Further, since both coal resources and gas resources in SPP are mostly owned by vertically integrated utilities and are typically located near load centers with access to well-networked transmission, the impact of changes of merit order on system congestion, if any, would be small compared to the impact of changes in fuel costs.

While I agree conceptually with Mr. Chiles that doing it all with one model would be preferable, that is simply not feasible given the limitations of each of the models. There is no single model that can feasibly model the long-term impact of new wind facilities on SWEPCO. It is consequently reasonable to use each model for its strengths and combine the results as the Company has done. I do not share Mr. Chiles' concerns that employing PROMOD to capture the congestion and loss-related costs associated with the delivery of outputs from the Selected Wind Facilities and then scaling them based on the AURORA fundamental forecast for market prices ignores the impacts of dispatch changes.

Q. MR. CHILES SUGGESTS THAT RATHER THAN USING THE MULTIPLE-MODEL APPROACH, THE COMPANY SHOULD DEVELOP TEN PROMOD CASES. DO YOU FIND THIS SUGGESTION REASONABLE?

A. No, I do not. First, for the reasons I explained previously, I do not share Mr. Chiles' concern that combining PROMOD and AURORA yields unreliable or unreasonable estimates for congestion costs for the Selected Wind Facilities. As explained in my direct testimony, the PROMOD case is a computationally intensive model of the entire Eastern interconnect and captures the long-term generation and transmission topology of SPP and neighboring areas. The SPP PROMOD case for select years and a very limited set of scenarios are developed annually through a resource- and staff-intensive stakeholder process administered by SPP. The currently available PROMOD models have been developed only for two study years

(2024 and 2029) and two scenarios (the Reference Case and Emerging Technologies Case). The years and cases are limited to just two because setting up and simulating more cases in PROMOD is very time consuming. In contrast, the Company's AURORA model produces long-term regional price trends, annually through 2050. Furthermore, AURORA is able to quickly analyze various sensitivities, such as under varying long-term gas and coal price forecasts, or future carbon tax assumptions.

V. PROJECT RISKS AND DISCOUNT RATES

Q. ON PAGES 61-64 MR. GRIFFEY SUGGESTS THAT THE BENEFITS OF THE SELECTED WIND PROJECTS ARE MORE RISKY THAN THEIR COSTS AND SHOULD BE DISCOUNTED AT A HIGHER RATE THAN SWEPCO'S AFTER-TAX COST OF CAPITAL OF 7.09%. DO YOU AGREE?

A. No, I do not. Mr. Griffey's suggestion is inappropriate and erroneous for at least four reasons. First, for regulated utility assets of average risk—be it wind generation or conventional generation—SWEPCO's weighted cost of capital (WACC) is the appropriate discount rate for costs and benefits. As a result, applying different discount rates to the costs and benefits of projects is contrary to standard industry practices. The standard practice to value an investment is to discount cash flows with the after-tax WACC. Using different discount rates for different components of these cash flows, such as wholesale market revenues or costs, would require the development of discount rates that differ significantly from applying a WACC. Doing so would be inconsistent with the approach that has been used before this Commission and other regulatory agencies. For example, Southwest Public Service Company (SPS) utilized its WACC of 6.35% as the (single) discount rate in the benefit-cost assessment of its wind projects in PUC Docket No. 46936, which was settled with full support of the TIEC witness and approved by the Commission. SPS did not use different discount rates for costs and benefits, as Mr. Griffey proposes, but instead used different sensitivity cases to evaluate the risks of the proposed facilities, like the Company did in this case.

Second, Mr. Griffey has provided no quantitative evidence that the risk of the Company's investment in the Selected Wind Facilities is quantifiably higher than the average risks reflected in SWEPCO's cost of capital. While Mr. Griffey suggests that the risk of the Selected Wind Facilities may be similar to merchant generation investments or that of oil and gas producers, he has not provided any quantitative evidence that this is in fact the case. While the WACC of merchant natural gas generators has been found to be in the 8.0% to 8.5% range, it is important to recognize that the risk of merchant wind generators would be lower, meaning that they would have an even lower WACC. This is because the investment cost recovery of merchant gas generators depends on "margins" (i.e., market prices less fuel costs) that are earned mostly during scarcity events in wholesale power market and that, consequently, are much more volatile than the wholesale power prices earned by merchant wind generators. There is consequently no evidence that the discount rates applied by AEP (7.09%) and SPS in Docket No. 46936 (6.35%) are too low to value the net customer benefits of the utilities' wind generation investments.

Third, Mr. Griffey's argument implicitly assumes that the "uncertainty" of customer benefits associated with the Selected Wind Projects translates to increased risks faced by the Company's customers—which is not at all the case. As Company witness Torpey has shown in his direct testimony and I have summarized in Figure 3 of my direct testimony, the variance of the Selected Wind Facilities' customer benefits serves to reduce the overall risks faced by the Company's customers. In possible future outcomes when overall customer costs are high—such as in a world with high natural gas prices, high SPP wholesale power prices, and the possibility of carbon charges—the projects' provide the largest benefits, thus offsetting high customer costs. In a future when overall customer costs are low—such as in a world with low natural gas prices, low SPP wholesale power prices, and the absence of carbon charges—the benefits of the projects are lower, although (as shown by Mr. Torpey's break-even analysis) still sufficient to cover the costs of the projects. Thus, the Company's investment in the Selected Wind Facilities reduces (not increases) the future uncertainty of overall customer costs. This is the hedging benefit I have discussed in my direct testimony. Given that the project benefits reduce the overall risk faced by the Company's customers, it would not make sense to discount the benefits at a rate higher than the Company's overall WACC.

Fourth, Mr. Griffey's suggestion that a 12.98% discount rate based on the "WACC" determined for the valuation of oil and gas properties by the Texas Comptroller would be more appropriate for valuing the Selected Wind Facilities is highly inappropriate and erroneous. In addition to there being no basis to apply the WACC of oil and gas producers to the Company's Selected Wind Facilities, the "WACC" calculated by the Texas Comptroller is not even the kind of after-tax WACC that would be needed for such an exercise. As is evident from the Comptroller report cited by Mr. Griffey, the "WACC" calculated in the Comptroller report is a "before-tax" WACC that necessarily is much higher than the after-tax WACC that needs to be applied to the valuation of project benefits. Table 1 on page 2 of the Comptroller report determined for oil and gas producers a cost of equity of 12.45% and a cost of debt of 5.1%, which yields an after-tax WACC for oil and gas companies of only 8.2%. The Comptroller utilizes a *before-tax* WACC because the particular valuation approach does not treat taxes as an expense, which makes this approach entirely inappropriate to valuations that explicitly consider tax expenses, such as those presented by the Company in this case. Moreover, for the reasons discussed above, the risks associated with the Company's ownership of the Selected Wind Facilities will be much lower than the risk of oil and gas properties.

VI. CONGESTION HEDGING

Q. DO YOU AGREE WITH MR. CHILES' STATEMENT THAT IT IS UNREASONABLE TO ASSUME THAT 25% OF CONGESTION WILL BE HEDGED WITH TCRS?

A. No. The 25% hedge ratio is reasonable as I explain below. Mr. Chiles' suggestion that rather than use the 25% congestion hedge assumption, the Company should use a 0% congestion hedge assumption is unreasonable.

Q. WHY IS THE ASSUMED 25% HEDGE RATIO REASONABLE?

A. The Company's assumption of a 25 percent hedge ratio is based on data of actual TCR congestion hedges realized in 2018 by SWEPCO's and PSO's contracted existing generation resources in the SPP footprint. As shown in the Highly Sensitive Confidential Exhibit JFG-2 (provided in exhibits to witness Jay Godfrey's Direct Testimony), TCR revenues realized on the Company's existing wind generation resources varied widely, depending on the resources' locations and deliverability of their outputs to the AEP load zone. In 2018, the output-weighted average realized hedge ratio across all of SWEPCO's and PSO's contracted wind generation resources was approximately 33 percent. SWEPCO conservatively assumed a lower hedge ratio of 25 percent for the Selected Facilities because, at the time of filing of the application, the Company had not yet requested firm transmission deliverability rights for the delivery of the Selected Wind Facilities outputs to the AEP load zone. This meant that, without firm deliverability rights that would allow the Company to obtain additional auction revenue rights (ARRs) that could be converted into TCRs, the Company would need to optimize its existing ARR allocations across all its congested generation-to-load paths, including the new delivery paths between the Selected Facilities and AEP loads. Without new ARR allocations for the Selected Facilities, the Company's optimal TCR portfolio may result in a tradeoff between some existing, lowered-congestion paths (e.g., from less constrained conventional company resources) and higher-congestion paths (such as those that may be associated with the Selected Facilities).

Since the filing of this application, the Company has begun the process of requesting long-term firm transmission deliverability rights from the Selected Wind Facilities under the SPP Tariff. As Company witness Ross explains in this rebuttal testimony, the Company's decision to obtain firm deliverability for the Selected Wind Facilities will depend on the outcome of SPP study, which is yet to be conducted. If the Company's request for firm deliverability rights for the Selected Wind Facilities is granted at no or only modest costs under the SPP tariff, the Selected Wind Facilities would receive new ARR allocations for delivery of their outputs to the AEP loads. In this case, there would not be any tradeoff between existing, lower-congestion paths and hedging congestion cost associated with the Selected Wind Facilities. In this case, customer benefits would be larger than the Company's estimated benefits. If firm delivery requires more substantial transmission upgrade costs, I understand the Company will evaluate the cost/benefit tradeoff and pursue firm transmission only if the increase in customer benefits exceeds the cost of the new transmission facilities.

VII. CONCLUSION

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

SOAH DOCKET NO. 473-19-6862

PUC DOCKET NO. 49737

PUBLIC UTILITY COMMISSION OF TEXAS

APPLICATION OF

SOUTHWESTERN ELECTRIC POWER COMPANY

FOR CERTIFICATE OF CONVENIENCE AND NECESSITY

AUTHORIZATION AND RELATED RELIEF FOR

THE ACQUISITION OF WIND GENERATION FACILITIES

REBUTTAL TESTIMONY OF

C. RICHARD ROSS

FOR

SOUTHWESTERN ELECTRIC POWER COMPANY

FEBRUARY 12, 2020

<u>TESTIMONY INDEX</u>

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is C. Richard Ross. My business address is 212 E 6th St, Tulsa, OK 74119.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A, I am currently the Managing Director Regional Transmission Organization (RTO) Policy and FERC Recovery for American Electric Power Service Corporation (AEPSC). I have been with American Electric Power Company (AEP) for 28 years working in a variety of areas including control area operations, energy planning, wholesale sales, retail supply and RTO Policy. I have served on a variety of regional working groups and, today, serve on the Southwest Power Pool (SPP) Strategic Planning Committee, Market and Operations Policy Committee, Market Working Group, Business Practices Working Group and Regional Cost Allocation Review Task Force and the Electric Reliability Council of Texas (ERCOT) Technical Advisory Committee. My organization coordinates the RTO representation and policy development for the AEP operating companies and business units. I have a B.S. in Electrical Engineering from Texas A & M University.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE REGULATORY AGENCIES?

A. Yes, I have testified before the Public Utility Commission of Texas (PUC or Commission), the Arkansas Public Service Commission, the Louisiana Public Service Commission, and the Oklahoma Corporation Commission.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN PUC DOCKET NO. 49737?

A. No, I have not.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to respond to the Statement of Position filed by Golden Spread Electric Cooperative (Golden Spread) in this proceeding. My testimony explains that Golden Spread's request that the Commission require Southwestern Electric Power Company (SWEPCO or the Company) to hold Golden Spread harmless for facility-related transmission costs assigned through the SPP's Open Access Transmission Tariff (OATT) is inappropriate. Golden Spread makes several claims that are inconsistent with the SPP OATT and inconsistent with SWEPCO's proposed project. Moreover, the SPP's OATT is a FERC-approved tariff that assigns transmission costs to SPP members on a fair and appropriate basis based on applicable benefits and it is not appropriate for Golden Spread to ask the Commission to disturb the results of this FERC tariff. If Golden Spread has an issue with the manner in which the SPP's OATT assigns transmission costs, the proper forum to address the complaint is FERC or a proposal to the SPP stakeholders, not this Commission.

III. RESPONSE TO GOLDEN SPREAD

Q. WHAT ARGUMENTS DO YOU ADDRESS IN YOUR TESTIMONY?

A. In the paragraphs that follow, I respond to Golden Spread's assertions that:

- SWEPCO's analysis did not consider the cost of building a generation tie line (Gen-Tie) or securing firm transmission service.
- Cost will be inappropriately shifted to Golden Spread if the Company builds a Gen-Tie or makes arrangements for firm transmission service.
- SWEPCO expects interconnection costs to be shifted to Golden Spread through the SPP Planning Process.

A. SWEPCO Analysis

Q. GOLDEN SPREAD COMPLAINS THAT THE FACILITY-RELATED TRANSMISSION COSTS SWEPCO CONSIDERED IN ANALYZING THE ECONOMICS OF THE SELECTED WIND FACILITIES DID NOT INCLUDE THE COSTS ASSOCIATED WITH CONSTRUCTING A GEN-TIE OR WITH OBTAINING FIRM TRANSMISSION SERVICE FROM SPP. IS THIS CRITICISM JUSTIFIED?

A. No, it is not. All of the project-related benefits identified in SWEPCO's Application (including the 15% capacity credit Golden Spread claims is dependent on firm transmission service) can be realized without the construction of a Gen-Tie or obtaining firm transmission service. Additionally, in its economic analysis, the Company presented a high congestion sensitivity case that included a Gen-Tie only to show that the proposed projects would still provide substantial customer benefits in that circumstance.

Q. DOES SWEPCO PLAN ON CONSTRUCTING A GEN-TIE FOR THE SELECTED WIND FACILITIES?

A. As explained by Company witness Kamran Ali, SWEPCO does not plan on building a Gen-Tie at this time. Not only is it not necessary to obtain all of the benefits identified in SWEPCO's Application, its cost is not justified based on the Company's current projections. Rather, the Gen-Tie remains a congestion-risk-mitigation option that could be exercised if congestion costs were to increase unexpectedly in the future.

B. No Cost Shifts

Q. GOLDEN SPREAD COMPLAINS THAT, IF SWEPCO WERE TO BUILD A GENERATION TIE LINE OR REQUEST FIRM TRANSMISSION SERVICE, COST WILL BE SHIFTED TO GOLDEN SPREAD INAPPROPRIATELY AND THEY SHOULD BE HELD HARMLESS. IS THIS CRITICISM AND PROPOSAL JUSTIFIED?

A. No. Golden Spread suggests that certain facility-related transmission costs that should be directly assigned to SWEPCO will somehow be inappropriately assigned to Golden Spread if SWEPCO were to build a Gen-Tie or arrange for firm transportation service from the SPP. This is wrong. The cost for any such transmission facilities will be assigned or allocated under the terms of the FERC-approved SPP OATT. As discussed below, costs that should be directly assigned to SWEPCO will in fact be directly assigned to SWEPCO, while system upgrades that also benefit others would be allocated regionally. These cost allocation procedures have been found to be just and reasonable by the FERC and, as a result, Golden Spread's request that this Commission require SWEPCO to hold Golden Spread "harmless" for these purported "reallocated" costs is inappropriate. In the event Golden Spread wishes to challenge the manner in which the SPP's OATT assigns such costs, the proper forum to address the complaint is FERC or a proposal to the SPP stakeholders, not this Commission.

As I explain in greater detail below, although SWEPCO has applied for firm transmission service from the SPP, neither a Gen-Tie nor firm transmission service is required for SWEPCO to receive the project-related benefits identified in SWEPCO's Application in this proceeding. Further, in either such case, the SPP's OATT is an SPP stakeholder- and FERC-approved tariff and it does not inappropriately assign costs to SPP members as Golden Spread argues.

Q. WHAT ARE THE VARIOUS WAYS THAT GENERATORS MAY BE INTERCONNECTED TO THE SPP'S TRANSMISSION GRID?

A. The SPP Generator Interconnection Procedures in Attachment V of the SPP OATT identify the facilities that are necessary to connect a generator project to the SPP Transmission System. These can include Interconnection Customer's Interconnection Facilities, Transmission Owner's Interconnection Facilities, and SPP Network Upgrades. Under this process, generators are required to select one of two types of generator interconnection services. The two types of service are Energy Only Resource Interconnection Service (ERIS) and Network Resource Interconnection Service (NRIS). The primary difference in the services is study parameters SPP utilizes to determine if upgrades will be attributed to the service. ERIS request studies, although capable of accommodating the full output of the resource, plan for a more limited interconnection service and typically result in fewer SPP Network Upgrade requirements in comparison to NRIS requests.

Q. WHAT TYPE OF INTERCONNECTION SERVICE HAS BEEN SECURED BY THE SUBJECT WIND FACILITIES?

A. The subject wind facilities will be interconnected under ERIS service agreements.

Q. IN THE EVENT THE COMPANY DECIDES TO CONSTRUCT A GENERATION TIE LINE IN THE FUTURE, WOULD THAT NEW GENERATION INTERCONNECTION FOLLOW THIS SAME PROCESS?

A. Yes.

Q. HOW IS THE COST OF THESE INTERCONNECTION FACILITIES ALLOCATED AMONG THE SPP MEMBERS?

A. The cost of the interconnection facilities is allocated to the Generator Interconnection Customer.

Q. ARE THERE PROVISIONS TO COMPENSATE GENERATION INTERCONNECTION CUSTOMERS FOR ANY OF THE COST OF THOSE FACILITIES?

A. The SPP OATT does include provisions to compensate Generation Interconnection Customers if SPP later determines it is utilizing facilities funded by Generator Interconnection Customers to provide new service to other Customers under the SPP OATT. The OATT also governs how the cost will be assigned to those using the facilities.

Q. WHAT IS LONG-TERM FIRM TRANSMISSION SERVICE?

A. Long-term firm transmission service is transmission service that SPP provides based on a study analyzing the transfer of power, without interruption, from a network resource to specific load.

Q. HAS SWEPCO APPLIED FOR LONG-TERM FIRM TRANSMISSION SERVICE FROM SPP FOR THE SUBJECT WIND FACILITIES?

A. Yes. Although not part of its application in this proceeding, SWEPCO has submitted requests for long-term firm transmission service for the subject wind facilities to the SPP. It was not possible to submit the long-term firm transmission service request prior to the initiation of this proceeding, due to the timing of when the Purchase and Sale Agreements were signed. The request for long-term firm transmission service was made so that SWEPCO can consider whether such service would be beneficial for customers. SWEPCO's requests, along with numerous other long-term firm transmission service requests for other customers, are being evaluated in SPP's 2019-AG2 aggregate facility study.

Q. WHEN DOES SWEPCO EXPECT TO RECEIVE SPP'S RESPONSE TO ITS REQUESTS?

A. Although it is currently uncertain, SWEPCO expects to receive an initial response to its requests for long-term firm transmission service from the SPP in mid-March, 2020 and the final study posted in May 2020. The response will identify any transmission upgrades necessary to provide the service and the cost responsibility attributable to SWEPCO's requests. Once SWEPCO receives this response from the SPP, it will decide whether obtaining firm transmission service for the subject wind facilities is justified. That decision will turn on whether the additional benefits of the service exceed the cost of any transmission upgrades required to obtain the service.

Q. HOW DOES SWEPCO ANTICIPATE THAT THE COSTS OF FIRM TRANSMISSION SERVICE WILL BE ALLOCATED?

A. Because the majority of the Megawatts requested will exceed SPP's "20% wind rule," it is expected that the majority of any upgrade costs will be directly assigned to SWEPCO. The 20% wind rule provides that when a company's wind resources exceed 20% of its total resources, any transmission grid upgrade costs attributable to the company adding new wind resources above the 20% level are directly assigned to the company. The funding of the upgrade costs, if any, that are not subject to this limitation will be determined in accordance with the cost allocation provisions of the SPP OATT.

Q. AS PART OF ITS REQUEST THAT IT BE HELD HARMLESS FROM SPP TRANSMISSION COST ALLOCATIONS, GOLDEN SPREAD REQUESTS THAT THE COMMISSION REQUIRE SWEPCO TO BOTH APPLY FOR FIRM TRANSMISSION SERVICE FROM SPP AND OBTAIN IT. IS THIS REQUEST REASONABLE?

A. No, Golden Spread's request is not reasonable. It would be unreasonable for SWEPCO to commit to obtaining firm transmission service for the Selected Wind Facilities in advance of determining the cost of the service. This is because it would be unreasonable to commit to the service if its costs exceed its benefits. Doing so would be unfair to SWEPCO's customers.

C. SPP PLANNING PROCESS

Q. GOLDEN SPREAD CLAIMS THAT SWEPCO "EXPECTS" TO SHIFT FACILITY-RELATED TRANSMISSION COSTS TO OTHER SPP MEMBERS THROUGH SPP'S REGIONAL TRANSMISSION PLANNING PROCESS. IS THIS TRUE?

A. No, this is not true. SWEPCO does not "expect" to shift any of its project costs to other SPP members. SPP's Integrated Transmission Planning (ITP) studies the needs of the

SPP Transmission System based on the system conditions now and in the future to determine the transmission projects that best meet the reliability needs and economic benefits for the SPP region. While SWEPCO does expect the assumptions in these studies to take the Selected Wind Facilities into consideration, it does not expect SPP to treat the Facilities any differently than any other similarly situated resource in the studies. SPP will conduct these ITP studies in accordance with the FERC approved SPP Tariff.

Q. GOLDEN SPREAD ALSO CLAIMS THAT IF SWEPCO WAITS UNTIL THE WIND FACILITIES ARE CONSIDERED IN SPP'S REGIONAL TRANSMISSION PLANNING PROCESS BEFORE IT OBTAINS FIRM TRANSMISSION SERVICE, IT IS LIKELY THAT TRANSMISSION BUILT PURSUANT TO THE SPP REGIONAL PROCESS WILL REDUCE THE UPGRADES THAT WOULD OTHERWISE BE ASSIGNED TO SWEPCO THROUGH THE FIRM TRANSMISSION PROCESS. IS THIS CRITICISM JUSTIFIED?

A. No, this criticism is not justified. Upgrades determined in future ITP studies will be based on transmission grid conditions existing at that time and any related costs will be allocated based on SPP's FERC-approved tariff. As stated earlier, such upgrades will be based on the reliability needs and economic benefits to the SPP region, not what is required to facilitate Firm Transmission Service from the resources to SWEPCO's load.

Q. GOLDEN SPREAD ALSO CLAIMS THAT THE LONGER SWEPCO WAITS BEFORE REQUESTING FIRM TRANSMISSION SERVICE THE MORE LIKELY IT IS THAT FACILITY-RELATED TRANSMISSION COSTS THAT SHOULD BE

BORNE BY SWEPCO WILL BE BORNE BY OTHER SPP MEMBERS? IS THIS CLAIM ACCURATE?

A. Again, this claim by Golden Spread is inaccurate. First, as explained above, SWEPCO has already applied to the SPP for firm transmission service and, if service is accepted, the majority of any identified upgrade costs will be directly assigned to SWEPCO. Second, any delay by SWEPCO to secure such services also increases the possibility that other Firm Transmission Service Customers will request service ahead of SWEPCO and consume the transmission capability that would otherwise be available to provide SWEPCO's service.

Q. IS IT APPROPRIATE FOR THIS COMMISSION TO CONSIDER, IN THIS PROCEEDING, WHETHER THE FERC-APPROVED SPP COST ALLOCATION METHODOLOGIES ARE FAIR AND WHETHER GOLDEN SPREAD SHOULD BE EXEMPTED FROM THE RESULTS OF THAT PROCESS?

A. No, it is inappropriate for Golden Spread to make such a request. First, Golden Spread could be among the entities whose service is facilitated by the Network Upgrades funded by the interconnection of the Selected Wind Facilities to the SPP transmission system. Second, Golden Spread may be among the entities that will also benefit from the upgrades required to provide SWEPCO Firm Transmission Service. Denying SWEPCO, through some hold harmless provision, any compensation provided under the SPP OATT would effectively shift the cost burden from Golden Spread and other SPP members to SWEPCO's customers.

IV. CONCLUSION

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. Golden Spread's request that the Commission require SWEPCO to hold Golden Spread harmless for facility-related transmission costs assigned through the SPP's OATT is inappropriate. Golden Spread makes speculative claims of potential future harm that inaccurately portray the manner in which the SPP OATT actually assigns costs. Golden Spread also makes presumptions about SWEPCO's plans or actions that are not based in fact.

To the extent Golden Spread is concerned with the manner in which SPP will *actually* assign costs, that concern is inappropriate for resolution in this case. The SPP's OATT is a FERC-approved tariff that assigns transmission costs to SPP customers on a fair and appropriate basis and it is not appropriate for Golden Spread to ask the Commission to disturb the results of this FERC tariff. If Golden Spread has an issue with the manner in which the SPP's OATT assigns transmission costs, the proper forum to address the complaint is FERC or a proposal to the SPP stakeholders, not this Commission.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

SOAH DOCKET NO. 473-19-6862

PUC DOCKET NO. 49737

PUBLIC UTILITY COMMISSION OF TEXAS

APPLICATION OF

SOUTHWESTERN ELECTRIC POWER COMPANY

FOR CERTIFICATE OF CONVENIENCE AND NECESSITY

AUTHORIZATION AND RELATED RELIEF FOR

THE ACQUISITION OF WIND GENERATION FACILITIES

REBUTTAL TESTIMONY OF

NOAH K. HOLLIS

FOR

SOUTHWESTERN ELECTRIC POWER COMPANY

FEBRUARY 12, 2020

TESTIMONY INDEX

SECTION PAGE

EXHIBITS

EXHIBITS	DESCRIPTION
EXHIBIT NKH-1R	S&P Key Credit Factors for the Regulated Utilities Industry
EXHIBIT NKH-2R	Bloomberg regression analysis

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Noah K. Hollis. My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A, I am employed by American Electric Power Service Corporation (AEPSC) as Manager of Corporate Finance. AEPSC, a wholly-owned subsidiary of American Electric Power Company, Inc. (AEP), provides centralized professional and other services to subsidiaries of AEP. AEP is the parent company of Southwestern Electric Power Company (SWEPCO or the Company) and Public Service Company of Oklahoma (PSO). AEPSC is SWEPCO's and PSO's service company.

Q. ARE YOU THE SAME NOAH K. HOLLIS WHO FILED DIRECT TESTIMONY IN THIS CASE?

A. Yes, I am.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to respond to certain arguments made in the Direct Testimony of Charles Griffey on behalf of Texas Industrial Energy Consumers (TIEC). Specifically, I explain why Mr. Griffey's arguments regarding alternative methods of considering the economic value of the Selected Wind Facilities are inappropriate in this case and should be rejected by the Commission.

III. RESPONSE TO GRIFFEY

Q. DOES MR. GRIFFEY CRITICIZE THE MANNER IN WHICH SWEPCO DETERMINED THE ECONOMIC BENEFITS ASSOCIATED WITH THE SELECTED WIND FACILITIES?

A. Yes. Mr. Griffey complains that SWEPCO should have employed an alternative type of transaction structure that would make more efficient use of the facilities' production tax credits (PTCs). Mr. Griffey also claims that the use of various economic tools (*i.e.*, consideration of the facilities' payback period and application of a hurdle rate and a risk-adjusted discount rate) would have led SWEPCO to conclude that ownership of the facilities was too risky and should not be undertaken.

As I explain in greater detail below, these arguments are inappropriate in this case. First, Mr. Griffey offers no evidence that another transaction structure would be more tax efficient. Second, the alternative structures that Mr. Griffey recommends would increase the complexity and risk of the investment and lead to increased costs. Finally, Mr. Griffey's application of alternative methods of economic evaluation are flawed and, in this case, are inferior to the economic evaluation method the company employed – the consideration of the projects' net present value. Upon consummation of the contemplated transactions, the Selected Wind Facilities will be regulated utility assets. They will earn a regulated rate of return and will be no more risky than other utility-owned, rate-regulated generation assets.

Q. PLEASE DESCRIBE THE TAX EFFICIENCY ISSUE MR. GRIFFEY RAISES.

A. Tax efficiency is the extent to which tax liability is minimized in a given financial situation. An ownership structure is said to be tax efficient if the tax liability is lower than the tax liability of alternative structures that achieve the same end. Mr. Griffey argues that if the Company utilized an alternative financial structure (*i.e.*, purchased power agreements (PPAs) with third parties or involved a "tax equity partner" similar to the partner expected to become involved in Northern Indiana Public Service Company's (NIPSCO) Rosewater Project Wind Farm transaction (Rosewater)),[1] project-related PTCs could be utilized as they are generated and not cost the customer any incremental carrying cost on the deferred tax asset. However, Mr. Griffey's arguments are flawed. His recommended alternative ownership structures would increase the transactions' overall cost and complexity. And, with respect to the involvement of a tax equity partner, until an actual partner is identified and final terms have been agreed upon, any measure of tax efficiency (and related costs) would be speculative.

Q. HOW WOULD THE ALTERNATIVE TRANSACTION STRUCTURE INVOLVING A TAX EQUITY PARTNER THAT MR. GRIFFEY RECOMMENDS INCREASE THE COMPLEXITY AND COST OF THE TRANSACTIONS?

A. A tax equity partner invests equity capital into a project for the right to receive all of the tax benefits associated with the PTCs and the depreciation of the project, as well as some cash flow, up to the point that the investor's desired rate of return is achieved. Once the project has been in service long enough for this required rate of return to be achieved, the allocation of benefits changes to allow the project sponsor (instead of the

[1] The Rosewater transaction referenced by Mr. Griffey involves a wind farm facility to be owned by NIPSCO. As part of that transaction, it is anticipated that a tax equity partner will become part owner of the facility for a period of time in exchange for some or all of the tax benefits associated with the project.

tax equity investor) to collect the remaining tax and cash benefits. However, in most cases, the sponsor is required to buy out the tax equity partner's investment at the fair market value at this point. The required after-tax return of a tax equity investor will vary, but will typically range between 6-8% for a minimum equity investment of 30-60%.[2] This is considerably higher than the alternative - the Company's incremental borrowing rate for debt financing of 4.395% (with a debt ratio of 52% debt in the capital structure) – and would therefore result in a higher weighted average cost of capital and increased customer costs.

Of course, all of these factors are dependent on the individual tax equity partner, the specific project, the timing and value of the PTCs, and the tax capacity of the tax equity partner. Further, the transaction costs associated with this type of investment (*i.e.*, legal fees, tax opinion costs, financial advisory fees, *etc.*) will be higher, in addition to the tax equity partner's higher required return. These increased transaction costs result from the fact that this type of complicated ownership structure typically requires, among other items, the establishment of a special purpose project company, equity investment by the utility in the project company, and a negotiated fixed price Virtual PPA or Contract for Differences between the utility and the special purpose entity. Any claim that this structure is more tax efficient, lower cost, and more beneficial to the customer, without having specified any of the relevant details to support the claim, is purely speculation and is erroneous.

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[2] "Tax Equity Financing: An Introduction and Policy Considerations." Congressional Research Service. April 17, 2019, pg 9.

This alternative structure effectively gives the tax equity investor a guaranteed equity-type return in exchange for taking lender-type risks leaving sponsor in a subordinated equity position and taking on the majority of the risk associated with the project. It bears further note that projects financed with tax equity typically are not able to utilize cheaper project level debt in their capital structure because tax equity investors do not want to be subordinated to lenders that take security interests (place liens) on the project. This has the result of increasing rather than decreasing the cost of capital.

Q. DOES MR. GRIFFEY'S DISCUSSION OF THE NIPSCO ROSEWATER PROJECT SUPPORT HIS ARGUMENT?

A. No, it does not. In fact, in the NIPSCO proceeding Mr. Griffey cites, he was critical of NIPSCO's inability to be 100% tax efficient even when a tax equity partner was involved.[3] Additionally, NIPSCO has not yet been able to secure a tax equity partner for the transaction. As a result, there is no evidence that this arrangement will be successful, much less any more tax efficient than the Company's proposal, and, at this point, the cost to customers is unknown.

Q. MR. GRIFFEY ALSO CLAIMS THAT SWEPCO COULD BETTER UTILIZE ITS PTCS IF IT ENTERED INTO PPAS WITH THIRD PARTIES OR WITH A RELATED ENTITY. IS THIS ACCURATE?

A. No, this is inaccurate for several reasons. First, it is not certain that a PPA with a third party would result in a more efficient use of PTCs. This is because most developers

[3] State of Indiana Regulatory Commission, Cause No. 45194, Direct Testimony of Charles S. Griffey on behalf of the Indiana Coal Council.

must utilize a tax equity partner (described above) to monetize the benefits of available PTCs as they usually do not have enough taxable income to use the benefits as they are generated.[4] And, as I explained previously, this structure leads to increases in the transaction and capital costs for the project[5]. Second, in addition to the higher cost of tax equity capital, with the passage of the Tax Cuts and Jobs Act in 2017, any potential tax equity partner's "tax appetite" is now 40% less that it was before the enactment of the tax rate change ((35%-21%)/35% = 40%). This means that available tax equity partners may be more selective regarding potential projects[6] and that a potential transaction may be more costly. Because of the lack of transparency in the use of the tax benefits of a project and of the scarcity of tax equity, every transaction is unique and it is simply not possible to determine whether a PPA would result in a more efficient use of PTCs until an actual transaction with actual parties is identified.

Q. IS THERE ALSO A CONCERN ABOUT HOW CREDIT RATING AGENCIES WOULD TREAT A PPA ENTERED INTO BY THE COMPANY?

A. Yes. As indicated in Rebuttal EXHIBIT NKH-1R, Standard and Poor's (S&P) considers PPAs as a fixed obligation to the Company, akin to debt: "We view long-term power purchase agreements (PPA) as creating fixed, debt-like financial obligations that represent substitutes for debt-financed capital investments in

[4] "The Law of Wind: A guide to business and legal issues." Stoel Rives LLP. Eighth Edition. Chapter 9. Pg 7.

[5] Wind Energy Finance in the United States: Current Practice and Opportunities. National Renewable Energy Laboratory. August 2017. Pg 13-14.

[6] "Tax Equity Roundtable 2018." Power Finance & Risk. www.powerfinancerisk.com, pg 3-4.

generation capacity."[7] However, S&P uses a group methodology when evaluating the whole of AEP's operating subsidiaries. Said differently, S&P looks at the entire AEP consolidated group and assigns a single group credit rating to each individual entity in the group instead of looking at each entity separately to assign a credit rating.[8] As a part of this process, S&P imputes a debt-like adjustment for debt equivalent obligations like PPAs that are then considered when determining credit rating metrics.

The adjustments to the credit metrics have the effect of increasing debt levels. Since there is no offsetting increase in cash flow or earnings like one would see with ownership, total adjusted debt increases. This results in an eroding of credit metrics and, potentially, the credit ratings of the company.

Q. IS MR. GRIFFEY CORRECT THAT THE COMPANY HAS DISMISSED THIS DEBT EQUIVALENCY CONCERN (PAGE 48)?

A. No, Mr. Griffey cites a Company email provided in discovery but takes it out of context. Although the email correspondence refers to the inability to support a debt equivalency argument (*i.e.*, how rating agencies would consider the debt-like obligation resulting from entering into long-term contracts) in Oklahoma regulatory proceedings, this does not mean that rating agencies do not consider PPAs as debt when assigning credit ratings. The context of the email Mr. Griffey is referring to was that it is difficult to prove that debt imputation related to PPAs is attributable to a specific AEP operating company because, as observed above, S&P employs a group rating

[7] Standard & Poor's Rating Services. "Key Credit Factors for the Regulated Utilities Industry." Nov. 19, 2013. Pg 14.

[8] S&P Global Ratings. "General Criteria: Group Rating Methodology." August 2019.

methodology that considers AEP as a whole and does not specifically consider each individual company. This can be seen in S&P's most recent rating report on AEP, where S&P clearly identifies $336 million of imputed debt adjustments related specifically to PPAs.[9]

Q. WHAT IS THE CONCEPT OF PAYBACK PERIOD THAT MR. GRIFFEY RAISES?

A. The concept of a payback period for evaluating an investment is a very simplistic method of analysis. It simply measures the number of periods it requires to recover the cost of an investment based on the amount of the initial investment cost and the periodic stream of cash flows generated by the investment in successive periods. For example, if I make a $50 investment in period 0, and in year one I receive cash flow of $20, and in year two I receive cash flow of $30, my payback period is two years. If the asset has a life of only two years, I will break even. If it has a life of greater than two years, I should make the investment. And if it has a life that is less than two years, I should forgo the investment.

Q. HOW DOES MR. GRIFFEY APPLY THE CONCEPT OF A PAYBACK PERIOD IN CONNECTION WITH THE SELECTED WIND FACILITIES?

A. Mr. Griffey applies the simple payback period rule in two ways, both of which are flawed. The first way Mr. Griffey calculates the payback period is by comparing the summation of the projects' revenue requirement over their 30-year life to the cash flows of the projects over that same period. This calculation, he claims, results in a payback period of 27 years, which he deems unacceptable when compared with the facilities'

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[9] "American Electric Power Co. Inc." S&P Global Ratings – Ratings Direct. January 31, 2020. Pg 11.

30-year life. However, this calculation is flawed because, instead of using project cost amounts, Mr. Griffey uses the revenue requirement equivalent as the projects' investment cost. As a result, Mr. Griffey's calculation uses a cost of $3.1 billion, instead of SWEPCO's share of the $1.996 billion total wind facility cost, as described in the direct testimony of Company witness Joseph DeRuntz and detailed in his Exhibit JGD-3. SWEPCO's 54.5% portion of the $1.996 billion total project cost of $1.996 billion is $1.088 billion. Mr. Griffey incorrectly uses $3.1 billion as the project cost, which is the summation of the nominal revenue requirement over the life of the projects for both PSO and SWEPCO's share. However, as Company witness John Torpey discusses in his Rebuttal Testimony, in the case of utility assets, because the customer does not provide the up front, initial investment, it is inappropriate for these purposes to consider the revenue requirement equivalent as the projects' cost. To put Mr. Griffey's calculation error into perspective, if we look at the total benefit stream to the customer, the payback period would only be 9 years, based on the benefits to the customer, inclusive of PTCs, congestion and losses and the carrying charge on the deferred tax asset, when using the appropriate initial investment cost of $1.088 billion. As a result, Mr. Griffey's error overstates the payback period by approximately 18-years. Because of Mr. Griffey's miscalculation, Mr. Griffey presumes that the project is overly risky.

It is similarly flawed when Mr. Griffey uses the discounted payback period method as he uses the same revenue requirement equivalent for the investment cost instead of SWEPCO's share of the total facility cost and, as described above, this leads to results that are similarly incorrect.

Further, the payback period method in and of itself is flawed for several reasons. Aside from being overly simplistic when used in isolation, a standard measure of payback periods for particular assets does not exist. This forces the analyst evaluating a project to arbitrarily set an acceptable payback period when making a judgement on whether or not to invest in a project. Since it is arbitrary, it provides little information to the analyst from which to derive a decision on an investment. The method is also flawed because it ignores all cash flows that occur after the payback period. In contrast, the method used by SWEPCO to evaluate the investments, the NPV method, considers all of the cash flows over the entire life of the project. As a leading corporate finance textbook has observed, the payback period rule, "with its arbitrary cutoff date and its blindness to cash flows after [the payback period], can lead to some flagrantly foolish decisions if used too literally."[10]

Q. WHAT IS A "HURDLE RATE?"

A. A hurdle rate is the minimum rate that a company must earn from an investment in an asset or project. For regulated electric utilities, the hurdle rate is the regulated weighted average cost of capital.

Q. HOW DOES MR. GRIFFEY APPLY THE CONCEPT OF A HURDLE RATE IN CONNECTION WITH THE SELECTED WIND FACILITIES?

A. Mr. Griffey applies the concept to these investments incorrectly. First, Mr. Griffey calculates the net present value of the projects' revenue requirement, net of PTCs and carrying charges on the deferred tax asset, using the appropriate discount rate of 7.09%,

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[10] Ross, Westerfield, and Jaffe. Corporate Finance, 6th edition. Summary of the Payback Period Rule. Pg 143.

the Company's weighted average cost of capital. Then he solves for a discount rate that will produce the same net present value total for production cost savings, congestion and losses, and capacity value. In doing so, he produces a discount rate of 9.01%. Mr. Griffey then compares the Company's regulated weighted average cost of capital of 7.09% to the 9.01% internal rate of return generated by the customer benefits and concludes that the approximately 2% difference between the two rates does not adequately compensate the Company for the incremental risk of the project.

Q. IS THIS AN APPROPRIATE USE OF THE CONCEPT OF A HURDLE RATE?

A. No, it is not. First, Mr. Griffey provides no support for any of these claims. Second, these two cash flow streams are not mutually exclusive but rather mutually inclusive to determine the net cash flow of a project. As stated above, the hurdle rate is the minimum rate a company must earn when investing in a project or an asset. It does not separate cash flows into costs and benefits to discount at separate and distinct rates as Mr. Griffey does, but discounts the net cash flow at a single rate. The appropriate method for determining the hurdle rate of a project is to use the investor's Internal Rate of Return. For a regulated entity like SWEPCO, this is its weighted average cost of capital, 7.09%. Because Mr. Griffey's 9.01% internal rate of return exceeds the Company's 7.09% hurdle rate, even by Mr. Griffey's own calculation and simple methodology, the investments are reasonable.

Q. WHAT IS THE CONCEPT OF A RISK-ADJUSTED DISCOUNT RATE?

A. A risk adjusted discount rate is a rate used in discounting the cash flows of a project or asset to reflect differential project/asset risk. For example, when comparing investments with different risk levels, different discount rates that reflect this difference in risk should be used to evaluate the investments.

Q. HOW DOES MR. GRIFFEY APPLY THE CONCEPT OF A RISK-ADJUSTED DISCOUNT RATE TO THE SELECTED WIND FACILITIES?

A. Mr. Griffey attempts to apply a "risk adjusted discount rate" to the avoided energy costs under the Low Gas/No CO2 case that is different and higher than the proper discount rate that should be used to determine the net present value of the costs.

Q. IS THIS AN APPROPRIATE USE OF THE CONCEPT OF A RISK-ADJUSTED DISCOUNT RATE?

A. No it is not. Again, the various scenarios provided in the Company's original filing reflect the risk under differing price scenarios. Mr. Griffey's approach only serves to further discount the customer benefit streams that already reflect the differing levels of risk. In essence, he double counts risks that are already accounted for in the Company's sensitivity analyses. As mentioned in Company witness Torpey's Rebuttal Testimony, the use of the various scenario cases (*e.g.*, Low-Gas No CO2, *etc.*) in the economic analysis reflects varying levels of risk associated with the facilities and provides the associated risk-adjusted benefit stream to the customer. Further, as discussed above, Mr. Griffey complicates the net present value analysis by discounting the benefits of the projects at a different discount rate than the costs and uses the projects' revenue requirement equivalent as the cost, which grossly overstates the cost and timing of the investment. As explained above, when evaluating an investment decision for an asset or a project, the investment in the project is the expenditure to first purchase the asset or project. This amount should be compared with the associated cash flows, discounted at the investor's cost of capital. For SWEPCO, this is the authorized weighted average cost of capital approved by the Commission. Using a risk adjusted discount rate to account for the risk that has already been included is double counting.

Q. MR. GRIFFEY CLAIMS THAT THE "RETURNS FOR NATURAL GAS AND POWER PRICES" AND THE "COST OF CAPITAL FOR OIL AND GAS PRODUCTION COMPANIES" WOULD BE APPROPRIATE DISCOUNT RATES TO USE TO DISCOUNT THE BENEFIT STREAMS ASSOCIATED WITH THESE WIND PROJECTS. DO YOU AGREE?

A. No. Again, for a regulated electric utility, the appropriate discount rate is the utility's regulated weighted average cost of capital. Mr. Griffey claims that, because two commodities are correlated, power prices and natural gas prices, the two industries are correlated, and therefore the use of the "cost of capital for oil and gas production companies" provided by the Texas Comptroller is the appropriate proxy for the cost of capital. However, this is erroneous. Mr. Griffey provides no support for the correlation between the regulated electric utility cost of capital and that of oil and natural gas production companies. In fact, there appears to be little correlation between the two. For example, EXHIBIT NKH-2R contains a regression analysis from Bloomberg comparing the S&P 500 Electric Utility Index to the S&P 500 Oil and Natural Gas Producers Index. These are stock market indexes where each component of the index is weighted relative to its total market capitalization. S&P 500 companies that are in the Oil and Natural Gas exploration and production business (Global Industry Classification Standard (GICS) level 4) and a basket of S&P 500 companies that are electric utilities (GICS level 3) represent different GICS levels meaning they are different industries and reflect differing levels of risk. Additionally, the correlation between the two indexes is 0.081. This means that only about 8% of the movement in one index is reflected in the other index. This indicates that the two are not, as Mr. Griffey claims, highly correlated. Therefore, it is wrong to use the discount rate referenced by Mr. Griffey, because it applies to an industry that has a different level of risk than regulated utilities and is not at all closely correlated to the electric utilities sector.

IV. CONCLUSION

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. Mr. Griffey offers no evidence that another transaction structure would be more tax efficient that the structure proposed by the Company. Further, the alternative structures that Mr. Griffey recommends would increase the complexity and risk of the investments and lead to increased costs. Finally, upon consummation of the contemplated transactions, the Selected Wind Facilities will be regulated utility assets. They will earn a regulated rate of return and will be no more risky than other utility-owned, rate-regulated generation assets. As such, Mr. Griffey's application of alternative methods of economic evaluation are flawed and, in this case, are inferior to the economic evaluation method the Company employed – the consideration of the projects' net present value.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

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Key Credit Factors For The Regulated Utilities Industry

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Table Of Contents

Table Of Contents (cont.)

Criteria | Corporates | Utilities:

Key Credit Factors For The Regulated Utilities Industry

*(**Editor's Note:** This criteria article supersedes "Key Credit Factors: Business And Financial Risks In The Investor-Owned Utilities Industry," published Nov. 26, 2008, "Assessing U.S. Utility Regulatory Environments," Nov. 7, 2007, and "Revised Methodology For Adjusting Amounts Reported By U.K. GAAP Water Companies For Infrastructure Renewals Accounting," Jan. 27, 2010.)*

1. Standard & Poor's Ratings Services is refining and adapting its methodology and assumptions for its Key Credit Factors: Criteria For Regulated Utilities. We are publishing these criteria in conjunction with our corporate criteria (see "Corporate Methodology, published Nov. 19, 2013). This article relates to our criteria article, "Principles Of Credit Ratings," Feb. 16, 2011.

2. This criteria article supersedes "Key Credit Factors: Business And Financial Risks In The Investor-Owned Utilities Industry," Nov. 26, 2008, "Criteria: Assessing U.S. Utility Regulatory Environments," Nov. 7, 2007, and "Revised Methodology For Adjusting Amounts Reported By U.K. GAAP Water Companies For Infrastructure Renewals Accounting," Jan. 27, 2010.

SCOPE OF THE CRITERIA

These criteria apply to entities where regulated utilities represent a material part of their business, other than U.S. public power, water, sewer, gas, and electric cooperative utilities that are owned by federal, state, or local governmental bodies or by ratepayers. A regulated utility is defined as a corporation that offers an essential or near-essential infrastructure product, commodity, or service with little or no practical substitute (mainly electricity, water, and gas), a business model that is shielded from competition (naturally, by law, shadow regulation, or by government policies and oversight), and is subject to comprehensive regulation by a regulatory body or implicit oversight of its rates (sometimes referred to as tariffs), service quality, and terms of service. The regulators base the rates that they set on some form of cost recovery, including an economic return on assets, rather than relying on a market price. The regulated operations can range from individual parts of the utility value chain (water, gas, and electricity networks or "grids," electricity generation, retail operations, etc.) to the entire integrated chain, from procurement to sales to the end customer. In some jurisdictions, our view of government support can also affect the final rating outcome, as per our government-related entity criteria (see "General Criteria: Rating Government-Related Entities: Methodology and Assumptions," Dec. 9, 2010).

SUMMARY OF THE CRITERIA

Standard & Poor's is updating its criteria for analyzing regulated utilities, applying its corporate criteria. The criteria for evaluating the competitive position of regulated utilities amend and partially supersede the "Competitive Position" section of the corporate criteria when evaluating these entities. The criteria for determining the cash flow leverage assessment partially supersede the "Cash Flow/Leverage" section of the corporate criteria for the purpose of evaluating regulated utilities. The section on liquidity for regulated utilities partially amends existing criteria. All other sections of the corporate criteria apply to the analysis of regulated utilities.

IMPACT ON OUTSTANDING RATINGS

These criteria could affect the issuer credit ratings of about 5% of regulated utilities globally due primarily to the introduction of new financial benchmarks in the corporate criteria. Almost all ratings changes are expected to be no more than one notch, and most are expected to be in an upward direction.

EFFECTIVE DATE AND TRANSITION

These criteria are effective immediately on the date of publication.

METHODOLOGY

Part I--Business Risk Analysis

Industry risk

Within the framework of Standard & Poor's general criteria for assessing industry risk, we view regulated utilities as a "very low risk" industry (category '1'). We derive this assessment from our view of the segment's low risk ('2') cyclicality and very low risk ('1') competitive risk and growth assessment.

In our view, demand for regulated utility services typically exhibits low cyclicality, being a function of such key drivers as employment growth, household formation, and general economic trends. Pricing is non-cyclical, since it is usually based in some form on the cost of providing service.

Cyclicality

We assess cyclicality for regulated utilities as low risk ('2'). Utilities typically offer products and services that are essential and not easily replaceable. Based on our analysis of global Compustat data, utilities had an average peak-to-trough (PTT) decline in revenues of about 6% during recessionary periods since 1952. Over the same period, utilities had an average PTT decline in EBITDA margin of about 5% during recessionary periods, with PTT EBITDA margin declines less severe in more recent periods. The PTT drop in profitability that occurred in the most recent recession (2007-2009) was less than the long-term average.

With an average drop in revenues of 6% and an average profitability decline of 5%, utilities' cyclicality assessment calibrates to low risk ('2'). We generally consider that the higher the level of profitability cyclicality in an industry, the higher the credit risk of entities operating in that industry. However, the overall effect of cyclicality on an industry's risk profile may be mitigated or exacerbated by an industry's competitive and growth environment.

Competitive risk and growth

We view regulated utilities as warranting a very low risk ('1') competitive risk and growth assessment. For competitive risk and growth, we assess four sub-factors as low, medium, or high risk. These sub-factors are:

- Effectiveness of industry barriers to entry;
- Level and trend of industry profit margins;
- Risk of secular change and substitution by products, services, and technologies; and
- Risk in growth trends.

Effectiveness of barriers to entry--low risk

Barriers to entry are high. Utilities are normally shielded from direct competition. Utility services are commonly naturally monopolistic (they are not efficiently delivered through competitive channels and often require access to public thoroughfares for distribution), and so regulated utilities are granted an exclusive franchise, license, or concession to serve a specified territory in exchange for accepting an obligation to serve all customers in that area and the regulation of its rates and operations.

Level and trend of industry profit margins--low risk

Demand is sometimes and in some places subject to a moderate degree of seasonality, and weather conditions can significantly affect sales levels at times over the short term. However, those factors even out over time, and there is little pressure on margins if a utility can pass higher costs along to customers via higher rates.

Risk of secular change and substitution of products, services, and technologies--low risk

Utility products and services are not overly subject to substitution. Where substitution is possible, as in the case of natural gas, consumer behavior is usually stable and there is not a lot of switching to other fuels. Where switching does occur, cost allocation and rate design practices in the regulatory process can often mitigate this risk so that utility profitability is relatively indifferent to the substitutions.

Risk in industry growth trends--low risk

As noted above, regulated utilities are not highly cyclical. However, the industry is often well established and, in our view, long-range demographic trends support steady demand for essential utility services over the long term. As a result, we would expect revenue growth to generally match GDP when economic growth is positive.

B. Country risk

In assessing "country risk" for a regulated utility, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology").

C. Competitive position

In the corporate criteria, competitive position is assessed as ('1') excellent, ('2') strong, ('3') satisfactory, ('4') fair, ('5') weak, or ('6') vulnerable.

The analysis of competitive position includes a review of:

- Competitive advantage,
- Scale, scope, and diversity,
- Operating efficiency, and
- Profitability.

In the corporate criteria we assess the strength of each of the first three components. Each component is assessed as either: (1) strong, (2) strong/adequate, (3) adequate, (4) adequate/weak, or (5) weak. After assessing these components, we determine the preliminary competitive position assessment by ascribing a specific weight to each component. The applicable weightings will depend on the company's Competitive Position Group Profile. The group profile for regulated utilities is "National Industries & Utilities," with a weighting of the three components as follows: competitive advantage (60%), scale, scope, and diversity (20%), and operating efficiency (20%). Profitability is assessed by combining two sub-components: level of profitability and the volatility of profitability.

"Competitive advantage" cannot be measured with the same sub-factors as competitive firms because utilities are not primarily subject to influence of market forces. Therefore, these criteria supersede the "competitive advantage" section of the corporate criteria. We analyze instead a utility's "regulatory advantage" (section 1 below).

Assessing regulatory advantage

The regulatory framework/regime's influence is of critical importance when assessing regulated utilities' credit risk because it defines the environment in which a utility operates and has a significant bearing on a utility's financial performance.

We base our assessment of the regulatory framework's relative credit supportiveness on our view of how regulatory stability, efficiency of tariff setting procedures, financial stability, and regulatory independence protect a utility's credit quality and its ability to recover its costs and earn a timely return. Our view of these four pillars is the foundation of a utility's regulatory support. We then assess the utility's business strategy, in particular its regulatory strategy and its ability to manage the tariff-setting process, to arrive at a final regulatory advantage assessment.

When assessing regulatory advantage, we first consider four pillars and sub-factors that we believe are key for a utility to recover all its costs, on time and in full, and earn a return on its capital employed:

Regulatory stability:

- Transparency of the key components of the rate setting and how these are assessed
- Predictability that lowers uncertainty for the utility and its stakeholders
- Consistency in the regulatory framework over time

Tariff-setting procedures and design:

- Recoverability of all operating and capital costs in full
- Balance of the interests and concerns of all stakeholders affected
- Incentives that are achievable and contained

Financial stability:

- Timeliness of cost recovery to avoid cash flow volatility
- Flexibility to allow for recovery of unexpected costs if they arise
- Attractiveness of the framework to attract long-term capital
- Capital support during construction to alleviate funding and cash flow pressure during periods of heavy investments

Regulatory independence and insulation:

- Market framework and energy policies that support long-term financeability of the utilities and that is clearly enshrined in law and separates the regulator's powers
- Risks of political intervention is absent so that the regulator can efficiently protect the utility's credit profile even during a stressful event

We have summarized the key characteristics of the assessments for regulatory advantage in table 1.

Table 1

Preliminary Regulatory Advantage Assessment

Qualifier	What it means	Guidance
Strong	The utility has a major regulatory advantage due to one or a combination of factors that support cost recovery and a return on capital combined with lower than average volatility of earnings and cash flows.	The utility operates in a regulatory climate that is transparent, predictable, and consistent from a credit perspective.
	There are strong prospects that the utility can sustain this advantage over the long term	The utility can fully and timely recover all its fixed and variable operating costs, investments and capital costs (depreciation and a reasonable return on the asset base).
	This should enable the utility to withstand economic downturns and political risks better than other utilities.	The tariff set may include a pass-through mechanism for major expenses such as commodity costs, or a higher return on new assets, effectively shielding the utility from volume and input cost risks
		Any incentives in the regulatory scheme are contained and symmetrical.
		The tariff set includes mechanisms allowing for a tariff adjustment for the timely recovery of volatile or unexpected operating and capital costs.
		There is a track record of earning a stable, compensatory rate of return in cash through various economic and political cycles and a projected ability to maintain that record.
		There is support of cash flows during construction of large projects, and pre-approval of capital investment programs and large projects lowers the risk of subsequent disallowances of capital costs
		The utility operates under a regulatory system that is sufficiently insulated from political intervention to efficiently protect the utility's credit risk profile even during stressful events
Adequate	The utility has some regulatory advantages and protection, but not to the extent that it leads to a superior business model or durable benefit.	It operates in a regulatory environment that is less transparent, less predictable, and less consistent from a credit perspective.
	The utility has some but not all drivers of well-managed regulatory risk. Certain regulatory factors support the business's long-term stability and viability but could result in periods of below-average levels of profitability and greater profit volatility. However, overall these regulatory drivers are partially offset by the utility's disadvantages or lack of sustainability of other factors.	The utility is exposed to delays or is not, with sufficient certainty, able to recover all of its fixed and variable operating costs, investments and capital costs (depreciation and a reasonable return on the asset base) within a reasonable time.
		Incentive ratemaking practices are asymmetrical and material, and could detract from credit quality.
		The utility is exposed to the risk that it doesn't recover unexpected or volatile costs in a full or less than timely manner due to lack of flexible reopeners or annual revenue adjustments.
		There is an uneven track record of earning a compensatory rate of return in cash through various economic and political cycles and a projected ability to maintain that record.

Table 1

Preliminary Regulatory Advantage Assessment (cont.)		
		There is little or no support of cash flows during construction, and investment decisions on large projects (and therefore the risk of subsequent disallowances of capital costs) rest mostly with the utility
		The utility operates under a regulatory system that is not sufficiently insulated from political intervention and is sometimes subject to overt political influence
Weak	The utility suffers from a complete breakdown of regulatory protection that places the utility at a significant disadvantage.	The utility operates in an opaque regulatory climate that lacks transparency, predictability, and consistency.
	The utility's regulatory risk is such that the long-term cost recovery and investment return is highly uncertain and materially delayed, leading to volatile or weak cash flows. There is the potential for material stranded assets with no prospect of recovery.	The utility cannot fully and/or timely recover its fixed and variable operating costs, investments, and capital costs (depreciation and a reasonable return on the asset base).
		There is a track record of earning minimal or negative rates of return in cash through various economic and political cycles and a projected inability to improve that record sustainably.
		The utility must make significant capital commitments with no solid legal basis for the full recovery of capital costs.
		Ratemaking practices actively harm credit quality.
		The utility is regularly subject to overt political influence.

After determining the preliminary regulatory advantage assessment, we then assess the utility's business strategy. Most importantly, this factor addresses the effectiveness of a utility's management of the regulatory risk in the jurisdiction(s) where it operates. In certain jurisdictions, a utility's regulatory strategy and its ability to manage the tariff-setting process effectively so that revenues change with costs can be a compelling regulatory risk factor. A utility's approach and strategies surrounding regulatory matters can create a durable "competitive advantage" that differentiates it from peers, especially if the risk of political intervention is high. The assessment of a utility's business strategy is informed by historical performance and its forward-looking business objectives. We evaluate these objectives in the context of industry dynamics and the regulatory climate in which the utility operates, as evaluated through the factors cited in paragraphs 24-27.

We modify the preliminary regulatory advantage assessment to reflect this influence positively or negatively. Where business strategy has limited effect relative to peers, we view the implications as neutral and make no adjustment. A positive assessment improves the preliminary regulatory advantage assessment by one category and indicates that management's business strategy is expected to bolster its regulatory advantage through favorable commission rulings beyond what is typical for a utility in that jurisdiction. Conversely, where management's strategy or businesses decisions result in adverse regulatory outcomes relative to peers, such as failure to achieve typical cost recovery or allowed returns, we adjust the preliminary regulatory advantage assessment one category worse. In extreme cases of poor strategic execution, the preliminary regulatory advantage assessment is adjusted by two categories worse (when possible; see table 2) to reflect management decisions that are likely to result in a significantly adverse regulatory outcome relative to peers.

Table 2

Determining The Final Regulatory Advantage Assessment

	--Strategy modifier--			
Preliminary regulatory advantage score	**Positive**	**Neutral**	**Negative**	**Very negative**
Strong	Strong	Strong	Strong/Adequate	Adequate
Strong/Adequate	Strong	Strong/Adequate	Adequate	Adequate/Weak
Adequate	Strong/Adequate	Adequate	Adequate/Weak	Weak
Adequate/Weak	Adequate	Adequate/Weak	Weak	Weak
Weak	Adequate/Weak	Weak	Weak	Weak

Scale, scope, and diversity

We consider the key factors for this component of competitive position to be primarily operational scale and diversity of the geographic, economic, and regulatory foot prints. We focus on a utility's markets, service territories, and diversity and the extent that these attributes can contribute to cash flow stability while dampening the effect of economic and market threats.

A utility that warrants a Strong or Strong/Adequate assessment has scale, scope, and diversity that support the stability of its revenues and profits by limiting its vulnerability to most combinations of adverse factors, events, or trends. The utility's significant advantages enable it to withstand economic, regional, competitive, and technological threats better than its peers. It typically is characterized by a combination of the following factors:

- A large and diverse customer base with no meaningful customer concentration risk, where residential and small to medium commercial customers typically provide most operating income.
- The utility's range of service territories and regulatory jurisdictions is better than others in the sector.
- Exposure to multiple regulatory authorities where we assess preliminary regulatory advantage to be at least Adequate. In the case of exposure to a single regulatory regime, the regulatory advantage assessment is either Strong or Strong/Adequate.
- No meaningful exposure to a single or few assets or suppliers that could hurt operations or could not easily be replaced.

A utility that warrants a Weak or Weak/Adequate assessment lacks scale, scope, and diversity such that it compromises the stability and sustainability of its revenues and profits. The utility's vulnerability to, or reliance on, various elements of this sub-factor is such that it is less likely than its peers to withstand economic, competitive, or technological threats. It typically is characterized by a combination of the following factors:

- A small customer base, especially if burdened by customer and/or industry concentration combined with little economic diversity and average to below-average economic prospects;
- Exposure to a single service territory and a regulatory authority with a preliminary regulatory advantage assessment of Adequate or Adequate/Weak; or
- Dependence on a single supplier or asset that cannot easily be replaced and which hurts the utility's operations.

We generally believe a larger service territory with a diverse customer base and average to above-average economic growth prospects provides a utility with cushion and flexibility in the recovery of operating costs and ongoing investment (including replacement and growth capital spending), as well as lessening the effect of external shocks (i.e., extreme local weather) since the incremental effect on each customer declines as the scale increases.

We consider residential and small commercial customers as having more stable usage patterns and being less exposed to periodic economic weakness, even after accounting for some weather-driven usage variability. Significant industrial exposure along with a local economy that largely depends on one or few cyclical industries potentially contributes to the cyclicality of a utility's load and financial performance, magnifying the effect of an economic downturn.

A utility's cash flow generation and stability can benefit from operating in multiple geographic regions that exhibit average to better than average levels of wealth, employment, and growth that underpin the local economy and support long-term growth. Where operations are in a single geographic region, the risk can be ameliorated if the region is sufficiently large, demonstrates economic diversity, and has at least average demographic characteristics.

The detriment of operating in a single large geographic area is subject to the strength of regulatory assessment. Where a utility operates in a single large geographic area and has a strong regulatory assessment, the benefit of diversity can be incremental.

Operating efficiency

We consider the key factors for this component of competitive position to be:

- Compliance with the terms of its operating license, including safety, reliability, and environmental standards;
- Cost management; and
- Capital spending: scale, scope, and management.

Relative to peers, we analyze how successful a utility management achieves the above factors within the levels allowed by the regulator in a manner that promotes cash flow stability. We consider how management of these factors reduces the prospect of penalties for noncompliance, operating costs being greater than allowed, and capital projects running over budget and time, which could hurt full cost recovery.

The relative importance of the above three factors, particularly cost and capital spending management, is determined by the type of regulation under which the utility operates. Utilities operating under robust "cost plus" regimes tend to be more insulated given the high degree of confidence costs will invariably be passed through to customers. Utilities operating under incentive-based regimes are likely to be more sensitive to achieving regulatory standards. This is particularly so in the regulatory regimes that involve active consultation between regulator and utility and market testing as opposed to just handing down an outcome on a more arbitrary basis.

In some jurisdictions, the absolute performance standards are less relevant than how the utility performs against the regulator's performance benchmarks. It is this performance that will drive any penalties or incentive payments and can be a determinant of the utilities' credibility on operating and asset-management plans with its regulator.

Therefore, we consider that utilities that perform these functions well are more likely to consistently achieve determinations that maximize the likelihood of cost recovery and full inclusion of capital spending in their asset bases. Where regulatory resets are more at the discretion of the utility, effective cost management, including of labor, may allow for more control over the timing and magnitude of rate filings to maximize the chances of a constructive outcome such as full operational and capital cost recovery while protecting against reputational risks.

A regulated utility that warrants a Strong or Strong/Adequate assessment for operating efficiency relative to peers generates revenues and profits through minimizing costs, increasing efficiencies, and asset utilization. It typically is characterized by a combination of the following:

- High safety record;
- Service reliability is strong, with a track record of meeting operating performance requirements of stakeholders, including those of regulators. Moreover, the utility's asset profile (including age and technology) is such that we have confidence that it could sustain favorable performance against targets;
- Where applicable, the utility is well-placed to meet current and potential future environmental standards;
- Management maintains very good cost control. Utilities with the highest assessment for operating efficiency have shown an ability to manage both their fixed and variable costs in line with regulatory expectations (including labor and working capital management being in line with regulator's allowed collection cycles); or
- There is a history of a high level of project management execution in capital spending programs, including large one-time projects, almost invariably within regulatory allowances for timing and budget.

A regulated utility that warrants an Adequate assessment for operating efficiency relative to peers has a combination of cost position and efficiency factors that support profit sustainability combined with average volatility. Its cost structure is similar to its peers. It typically is characterized by a combination of the following factors:

- High safety performance;
- Service reliability is satisfactory with a track record of mostly meeting operating performance requirements of stakeholders, including those of regulators. We have confidence that a favorable performance against targets can be mostly sustained;
- Where applicable, the utility may be challenged to comply with current and future environmental standards that could increase in the medium term;
- Management maintains adequate cost control. Utilities that we assess as having adequate operating efficiency mostly manage their fixed and variable costs in line with regulatory expectations (including labor and working capital management being mostly in line with regulator's allowed collection cycles); or
- There is a history of adequate project management skills in capital spending programs within regulatory allowances for timing and budget.

A regulated utility that warrants a weak or weak/adequate assessment for operating efficiency relative to peers has a combination of cost position and efficiency factors that fail to support profit sustainability combined with below-average volatility. Its cost structure is worse than its peers. It typically is characterized by a combination of the following:

- Poor safety performance;
- Service reliability has been sporadic or non-existent with a track record of not meeting operating performance requirements of stakeholders, including those of regulators. We do not believe the utility can consistently meet performance targets without additional capital spending;
- Where applicable, the utility is challenged to comply with current environmental standards and is highly vulnerable to more onerous standards;
- Management typically exceeds operating costs authorized by regulators;
- Inconsistent project management skills as evidenced by cost overruns and delays including for maintenance capital spending; or
- The capital spending program is large and complex and falls into the weak or weak/adequate assessment, even if

operating efficiency is generally otherwise considered adequate.

Profitability

A utility with above-average profitability would, relative to its peers, generally earn a rate of return at or above what regulators authorize and have minimal exposure to earnings volatility from affiliated unregulated business activities or market-sensitive regulated operations. Conversely, a utility with below-average profitability would generally earn rates of return well below the authorized return relative to its peers or have significant exposure to earnings volatility from affiliated unregulated business activities or market-sensitive regulated operations.

The profitability assessment consists of "level of profitability" and "volatility of profitability."

Level of profitability

Key measures of general profitability for regulated utilities commonly include ratios, which we compare both with those of peers and those of companies in other industries to reflect different countries' regulatory frameworks and business environments:

- EBITDA margin,
- Return on capital (ROC), and
- Return on equity (ROE).

In many cases, EBITDA as a percentage of sales (i.e., EBITDA margin) is a key indicator of profitability. This is because the book value of capital does not always reflect true earning potential, for example when governments privatize or restructure incumbent state-owned utilities. Regulatory capital values can vary with those of reported capital because regulatory capital values are not inflation-indexed and could be subject to different assumptions concerning depreciation. In general, a country's inflation rate or required rate of return on equity investment is closely linked to a utility company's profitability. We do not adjust our analysis for these factors, because we can make our assessment through a peer comparison.

For regulated utilities subject to full cost-of-service regulation and return-on-investment requirements, we normally measure profitability using ROE, the ratio of net income available for common stockholders to average common equity. When setting rates, the regulator ultimately bases its decision on an authorized ROE. However, different factors such as variances in costs and usage may influence the return a utility is actually able to earn, and consequently our analysis of profitability for cost-of-service-based utilities centers on the utility's ability to consistently earn the authorized ROE.

We will use return on capital when pass-through costs distort profit margins--for instance congestion revenues or collection of third-party revenues. This is also the case when the utility uses accelerated depreciation of assets, which in our view might not be sustainable in the long run.

Volatility of profitability

We may observe a clear difference between the volatility of actual profitability and the volatility of underlying regulatory profitability. In these cases, we could use the regulatory accounts as a proxy to judge the stability of earnings.

We use actual returns to calculate the standard error of regression for regulated utility issuers (only if there are at least seven years of historical annual data to ensure meaningful results). If we believe recurring mergers and acquisitions or currency fluctuations affect the results, we may make adjustments.

Part II--Financial Risk Analysis

D. Accounting

Our analysis of a company's financial statements begins with a review of the accounting to determine whether the statements accurately measure a company's performance and position relative to its peers and the larger universe of corporate entities. To allow for globally consistent and comparable financial analyses, our rating analysis may include quantitative adjustments to a company's reported results. These adjustments also align a company's reported figures with our view of underlying economic conditions and give us a more accurate portrayal of a company's ongoing business. We discuss adjustments that pertain broadly to all corporate sectors, including this sector, in "Corporate Methodology: Ratios And Adjustments." Accounting characteristics and analytical adjustments unique to this sector are discussed below.

Accounting characteristics

Some important accounting practices for utilities include:

- For integrated electric utilities that meet native load obligations in part with third-party power contracts, we use our purchased power methodology to adjust measures for the debt-like obligation such contracts represent (see below).
- Due to distortions in leverage measures from the substantial seasonal working-capital requirements of natural gas distribution utilities, we adjust inventory and debt balances by netting the value of inventory against outstanding short-term borrowings. This adjustment provides an accurate view of the company's balance sheet by reducing seasonal debt balances when we see a very high certainty of near-term cost recovery (see below).
- We deconsolidate securitized debt (and associated revenues and expenses) that has been accorded specialized recovery provisions (see below).
- For water utilities that report under U.K. GAAP, we adjust ratios for infrastructure renewals accounting, which permits water companies to capitalize the maintenance spending on their infrastructure assets (see below). The adjustments aim to make those water companies that report under U.K. GAAP more comparable to those that report under accounting regimes that do not permit infrastructure renewals accounting.

In the U.S. and selectively in other regions, utilities employ "regulatory accounting," which permits a rate-regulated company to defer some revenues and expenses to match the timing of the recognition of those items in rates as determined by regulators. A utility subject to regulatory accounting will therefore have assets and liabilities on its books that an unregulated corporation, or even regulated utilities in many other global regions, cannot record. We do not adjust GAAP earnings or balance-sheet figures to remove the effects of regulatory accounting. However, as more countries adopt International Financial Reporting Standards (IFRS), the use of regulatory accounting will become more scarce. IFRS does not currently provide for any recognition of the effects of rate regulation for financial reporting purposes, but it is considering the use of regulatory accounting. We do not anticipate altering our fundamental financial analysis of utilities because of the use or non-use of regulatory accounting. We will continue to analyze the effects of regulatory actions on a utility's financial health.

Purchased power adjustment

We view long-term purchased power agreements (PPA) as creating fixed, debt-like financial obligations that represent substitutes for debt-financed capital investments in generation capacity. By adjusting financial measures to incorporate PPA fixed obligations, we achieve greater comparability of utilities that finance and build generation capacity and those that purchase capacity to satisfy new load. PPAs do benefit utilities by shifting various risks to the electricity generators, such as construction risk and most of the operating risk. The principal risk borne by a utility that relies on PPAs is recovering the costs of the financial obligation in rates. (See "Standard & Poor's Methodology For Imputing Debt for U.S. Utilities' Power Purchase Agreements," May 7, 2007, for more background and information on the adjustment.)

We calculate the present value (PV) of the future stream of capacity payments under the contracts as reported in the financial statement footnotes or as supplied directly by the company. The discount rate used is the same as the one used in the operating lease adjustment, i.e., 7%. For U.S. companies, notes to the financial statements enumerate capacity payments for the coming five years, and a thereafter period. Company forecasts show the detail underlying the thereafter amount, or we divide the amount reported as thereafter by the average of the capacity payments in the preceding five years to get an approximation of annual payments after year five.

We also consider new contracts that will start during the forecast period. The company provides us the information regarding these contracts. If these contracts represent extensions of existing PPAs, they are immediately included in the PV calculation. However, a contract sometimes is executed in anticipation of incremental future needs, so the energy will not flow until some later period and there are no interim payments. In these instances, we incorporate that contract in our projections, starting in the year that energy deliveries begin under the contract. The projected PPA debt is included in projected ratios as a current rating factor, even though it is not included in the current-year ratio calculations.

The PV is adjusted to reflect regulatory or legislative cost-recovery mechanisms when present. Where there is no explicit regulatory or legislative recovery of PPA costs, as in most European countries, the PV may be adjusted for other mitigating factors that reduce the risk of the PPAs to the utility, such as a limited economic importance of the PPAs to the utility's overall portfolio.The adjustment reduces the debt-equivalent amount by multiplying the PV by a specific risk factor.

Risk factors based on regulatory or legislative cost recovery typically range between 0% and 50%, but can be as high as 100%. A 100% risk factor would signify that substantially all risk related to contractual obligations rests on the company, with no regulatory or legislative support. A 0% risk factor indicates that the burden of the contractual payments rests solely with ratepayers, as when the utility merely acts as a conduit for the delivery of a third party's electricity. These utilities are barred from developing new generation assets, and the power supplied to their customers is sourced through a state auction or third parties that act as intermediaries between retail customers and electricity suppliers. We employ a 50% risk factor in cases where regulators use base rates for the recovery of the fixed PPA costs. If a regulator has established a separate adjustment mechanism for recovery of all prudent PPA costs, a risk factor of 25% is employed. In certain jurisdictions, true-up mechanisms are more favorable and frequent than the review of base rates, but still do not amount to pure fuel adjustment clauses. Such mechanisms may be triggered by financial thresholds or passage of prescribed periods of time. In these instances, a risk factor between 25% and 50% is employed. Specialized, legislatively created cost-recovery mechanisms may lead to risk factors between 0% and 15%, depending on the legislative provisions for cost recovery and the supply function borne by the utility. Legislative guarantees of complete and timely recovery of costs are particularly important to achieving the lowest risk factors. We also exclude short-term PPAs where they serve merely as gap fillers, pending either the construction of new capacity or the execution of long-term PPAs.

Where there is no explicit regulatory or legislative recovery of PPA costs, the risk factor is generally 100%. We may use a lower risk factor if mitigating factors reduce the risk of the PPAs on the utility. Mitigating factors include a long position in owned generation capacity relative to the utility's customer supply needs that limits the importance of the PPAs to the utility or the ability to resell power in a highly liquid market at minimal loss. A utility with surplus owned generation capacity would be assigned a risk factor of less than 100%, generally 50% or lower, because we would assess its reliance on PPAs as limited. For fixed capacity payments under PPAs related to renewable power, we use a risk factor of less than 100% if the utility benefits from government subsidies. The risk factor reflects the degree of regulatory recovery through the government subsidy.

Given the long-term mandate of electric utilities to meet their customers' demand for electricity, and also to enable comparison of companies with different contract lengths, we may use an evergreening methodology. Evergreen treatment extends the duration of short- and intermediate-term contracts to a common length of about 12 years. To quantify the cost of the extended capacity, we use empirical data regarding the cost of developing new peaking capacity, incorporating regional differences. The cost of new capacity is translated into a dollars-per-kilowatt-year figure using a proxy weighted-average cost of capital and a proxy capital recovery period.

Some PPAs are treated as operating leases for accounting purposes--based on the tenor of the PPA or the residual value of the asset on the PPA's expiration. We accord PPA treatment to those obligations, in lieu of lease treatment; rather, the PV of the stream of capacity payments associated with these PPAs is reduced to reflect the applicable risk factor.

Long-term transmission contracts can also substitute for new generation, and, accordingly, may fall under our PPA methodology. We sometimes view these types of transmission arrangements as extensions of the power plants to which they are connected or the markets that they serve. Accordingly, we impute debt for the fixed costs associated with such transmission contracts.

Adjustment procedures:

- Data requirements:
- Future capacity payments obtained from the financial statement footnotes or from management.
- Discount rate: 7%.
- Analytically determined risk factor.

- Calculations:
- Balance sheet debt is increased by the PV of the stream of capacity payments multiplied by the risk factor.
- Equity is not adjusted because the recharacterization of the PPA implies the creation of an asset, which offsets the debt.
- Property, plant, and equipment and total assets are increased for the implied creation of an asset equivalent to the

debt.

- An implied interest expense for the imputed debt is determined by multiplying the discount rate by the amount of imputed debt (or average PPA imputed debt, if there is fluctuation of the level), and is added to interest expense.
- We impute a depreciation component to PPAs. The depreciation component is determined by multiplying the relevant year's capacity payment by the risk factor and then subtracting the implied PPA-related interest for that year. Accordingly, the impact of PPAs on cash flow measures is tempered.
- The cost amount attributed to depreciation is reclassified as capital spending, thereby increasing operating cash flow and funds from operations (FFO).
- Some PPA contracts refer only to a single, all-in energy price. We identify an implied capacity price within such an all-in energy price, to determine an implied capacity payment associated with the PPA. This implied capacity payment is expressed in dollars per kilowatt-year, multiplied by the number of kilowatts under contract. (In cases that exhibit markedly different capacity factors, such as wind power, the relation of capacity payment to the all-in charge is adjusted accordingly.)
- Operating income before depreciation and amortization (D&A) and EBITDA are increased for the imputed interest expense and imputed depreciation component, the total of which equals the entire amount paid for PPA (subject to the risk factor).
- Operating income after D&A and EBIT are increased for interest expense.

Natural gas inventory adjustment

In jurisdictions where a pass-through mechanism is used to recover purchased natural gas costs of gas distribution utilities within one year, we adjust for seasonal changes in short-debt tied to building inventories of natural gas in non-peak periods for later use to meet peak loads in peak months. Such short-term debt is not considered to be part of the utility's permanent capital. Any history of non-trivial disallowances of purchased gas costs would preclude the use of this adjustment. The accounting of natural gas inventories and associated short-term debt used to finance the purchases must be segregated from other trading activities.

Adjustment procedures:

- Data requirements:
- Short-term debt amount associated with seasonal purchases of natural gas devoted to meeting peak-load needs of captive utility customers (obtained from the company).

- Calculations:
- Adjustment to debt--we subtract the identified short-term debt from total debt.

Securitized debt adjustment

For regulated utilities, we deconsolidate debt (and associated revenues and expenses) that the utility issues as part of a securitization of costs that have been segregated for specialized recovery by the government entity constitutionally authorized to mandate such recovery if the securitization structure contains a number of protective features:

- An irrevocable, non-bypassable charge and an absolute transfer and first-priority security interest in transition property;
- Periodic adjustments ("true-up") of the charge to remediate over- or under-collections compared with the debt service obligation. The true-up ensures collections match debt service over time and do not diverge significantly in the short run; and,
- Reserve accounts to cover any temporary short-term shortfall in collections.

Full cost recovery is in most instances mandated by statute. Examples of securitized costs include "stranded costs" (above-market utility costs that are deemed unrecoverable when a transition from regulation to competition occurs) and unusually large restoration costs following a major weather event such as a hurricane. If the defined features are present, the securitization effectively makes all consumers responsible for principal and interest payments, and the utility is simply a pass-through entity for servicing the debt. We therefore remove the debt and related revenues and expenses from our measures. (See "Securitizing Stranded Costs," Jan. 18, 2001, for background information.)

Adjustment procedures:

- Data requirements:
- Amount of securitized debt on the utility's balance sheet at period end;
- Interest expense related to securitized debt for the period; and
- Principal payments on securitized debt during the period.

- Calculations:
- Adjustment to debt: We subtract the securitized debt from total debt.
- Adjustment to revenues: We reduce revenue allocated to securitized debt principal and interest. The adjustment is the sum of interest and principal payments made during the year.
- Adjustment to operating income after depreciation and amortization (D&A) and EBIT: We reduce D&A related to the securitized debt, which is assumed to equal the principal payments during the period. As a result, the reduction to operating income after D&A is only for the interest portion.
- Adjustment to interest expense: We remove the interest expense of the securitized debt from total interest expense.

- Operating cash flows:
- We reduce operating cash flows for revenues and increase for the assumed interest amount related to the securitized debt. This results in a net decrease to operating cash flows equal to the principal repayment amount.

Infrastructure renewals expenditure

In England and Wales, water utilities can report under either IFRS or U.K. GAAP. Those that report under U.K. GAAP are allowed to adopt infrastructure renewals accounting, which enables the companies to capitalize the maintenance spending on their underground assets, called infrastructure renewals expenditure (IRE). Under IFRS, infrastructure renewals accounting is not permitted and maintenance expenditure is charged to earnings in the year incurred. This difference typically results in lower adjusted operating cash flows for those companies that report maintenance expenditure as an operating cash flow under IFRS, than for those that report it as capital expenditure under U.K. GAAP. We therefore make financial adjustments to amounts reported by water issuers that apply U.K. GAAP, with the aim of making ratios more comparable with those issuers that report under IFRS and U.S. GAAP. For example, we deduct IRE from EBITDA and FFO.

IRE does not always consist entirely of maintenance expenditure that would be expensed under IFRS. A portion of IRE can relate to costs that would be eligible for capitalization as they meet the recognition criteria for a new fixed asset set out in International Accounting Standard 16 that addresses property, plant, and equipment. In such cases, we may refine our adjustment to U.K. GAAP companies so that we only deduct from FFO the portion of IRE that would not be capitalized under IFRS. However, the information to make such a refinement would need to be of high quality, reliable, and ideally independently verified by a third party, such as the company's auditor. In the absence of this, we assume that the entire amount of IRE would have been expensed under IFRS and we accordingly deduct the full expenditure from FFO.

Adjustment procedures:

- Data requirements:
- U.K. GAAP accounts typically provide little information on the portion of capital spending that relates to renewals accounting, or the related depreciation, which is referred to as the infrastructure renewals charge. The information we use for our adjustments is, however, found in the regulatory cost accounts submitted annually by the water companies to the Water Services Regulation Authority, which regulates all water companies in England and Wales.

- Calculations:
- EBITDA: Reduced by the value of IRE that was capitalized in the period.
- EBIT: Adjusted for the difference between the adjustment to EBITDA and the reduction in the depreciation expense, depending on the degree to which the actual cash spending in the current year matches the planned spending over the five-year regulatory review period.
- Cash flow from operations and FFO: Reduced by the value of IRE that was capitalized in the period.
- Capital spending: Reduced by the value of infrastructure renewals spending that we reclassify to cash flow from operations.
- Free operating cash flow: No impact, as the reduction in operating cash flows is exactly offset by the reduction in capital spending.

E. Cash flow/leverage analysis

In assessing the cash flow adequacy of a regulated utility, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology"). We assess cash flow/leverage on a six-point scale ranging from ('1') minimal to ('6') highly leveraged. These scores are determined by aggregating the assessments of a range of credit ratios, predominantly cash flow-based, which complement each other by focusing attention on the different levels of a company's cash flow waterfall in relation to its obligations.

The corporate methodology provides benchmark ranges for various cash flow ratios we associate with different cash flow leverage assessments for standard volatility, medial volatility, and low volatility industries. The tables of benchmark ratios differ for a given ratio and cash flow leverage assessment along two dimensions: the starting point for the ratio range and the width of the ratio range.

If an industry's volatility levels are low, the threshold levels for the applicable ratios to achieve a given cash flow leverage assessment are less stringent, although the width of the ratio range is narrower. Conversely, if an industry has standard levels of volatility, the threshold levels for the applicable ratios to achieve a given cash flow leverage assessment may be elevated, but with a wider range of values.

We apply the "low-volatility" table to regulated utilities that qualify under the corporate criteria and with all of the following characteristics:

- A vast majority of operating cash flows come from regulated operations that are predominantly at the low end of the utility risk spectrum (e.g., a "network," or distribution/transmission business unexposed to commodity risk and with very low operating risk);
- A "strong" regulatory advantage assessment;

- An established track record of normally stable credit measures that is expected to continue;
- A demonstrated long-term track record of low funding costs (credit spread) for long-term debt that is expected to continue; and
- Non-utility activities that are in a separate part of the group (as defined in our group rating methodology) that we consider to have "nonstrategic" group status and are not deemed high risk and/or volatile.

We apply the "medial volatility" table to companies that do not qualify under paragraph 78 with:

- A majority of operating cash flows from regulated activities with an "adequate" or better regulatory advantage assessment; or
- About one-third or more of consolidated operating cash flow comes from regulated utility activities with a "strong" regulatory advantage and where the average of its remaining activities have a competitive position assessment of '3' or better.

We apply the "standard-volatility" table to companies that do not qualify under paragraph 79 and with either:

- About one-third or less of its operating cash flow comes from regulated utility activities, regardless of its regulatory advantage assessment; or
- A regulatory advantage assessment of "adequate/weak" or "weak."

Part III--Rating Modifiers

F. Diversification/portfolio effect

In assessing the diversification/portfolio effect on a regulated utility, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology").

G. Capital structure

In assessing the quality of the capital structure of a regulated utility, we use the same methodology as with other corporate issuers (see "Corporate Methodology").

H. Liquidity

In assessing a utility's liquidity/short-term factors, our analysis is consistent with the methodology that applies to corporate issuers (See "Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers," Nov. 19, 2013) except for the standards for "adequate" liquidity set out in paragraph 84 below.

The relative certainty of financial performance by utilities operating under relatively predictable regulatory monopoly frameworks make these utilities attractive to investors even in times of economic stress and market turbulence compared to conventional industrials. For this reason, utilities with business risk profiles of at least "satisfactory" meet our definition of "adequate" liquidity based on a slightly lower ratio of sources to uses of funds of 1.1x compared with the standard 1.2x. Also, recognizing the cash flow stability of regulated utilities we allow more discretion when calculating covenant headroom. We consider that utilities have adequate liquidity if they generate positive sources over uses, even if forecast EBITDA declines by 10% (compared with the 15% benchmark for corporate issuers) before covenants are breached.

I. Financial policy

In assessing financial policy on a regulated utility, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology").

J. Management and governance

In assessing management and governance on a regulated utility, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology").

K. Comparable ratings analysis

In assessing the comparable ratings analysis on a regulated utility, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology").

Appendix--Frequently Asked Questions

Does Standard & Poor's expect that the business strategy modifier to the preliminary regulatory advantage will be used extensively?

Globally, we expect management's influence will be neutral in most jurisdictions. Where the regulatory assessment is "strong," it is less likely that a negative business strategy modifier would be used due to the nature of the regulatory regime that led to the "strong" assessment in the first place. Utilities in "adequate/weak" and "weak" regulatory regimes are challenged to outperform due to the uncertainty of such regulatory regimes. For a positive use of the business strategy modifier, there would need to be a track record of the utility consistently outperforming the parameters laid down under a regulatory regime, and we would need to believe this could be sustained. The business strategy modifier is most likely to be used when the preliminary regulatory advantage assessment is "strong/adequate" because the starting point in the assessment is reasonably supportive, and a utility has shown it manages regulatory risk better or worse than its peers in that regulatory environment and we expect that advantage or disadvantage will persist. An example would be a utility that can consistently earn or exceed its authorized return in a jurisdiction where most other utilities struggle to do so. If a utility is treated differently by a regulator due to perceptions of poor customer service or reliability and the "operating efficiency" component of the competitive position assessment does not fully capture the effect on the business risk profile, a negative business strategy modifier could be used to accurately incorporate it into our analysis. We expect very few utilities will be assigned a "very negative" business strategy modifier.

Does a relatively strong or poor relationship between the utility and its regulator compared with its peers in the same jurisdiction necessarily result in a positive or negative adjustment to the preliminary regulatory advantage assessment?

No. The business strategy modifier is used to differentiate a company's regulatory advantage within a jurisdiction where we believe management's business strategy has and will positively or negatively affect regulatory outcomes beyond what is typical for other utilities in that jurisdiction. For instance, in a regulatory jurisdiction where allowed returns are negotiated rather than set by formula, a utility that is consistently authorized higher returns (and is able to earn that return) could warrant a positive adjustment. A management team that cannot negotiate an approved capital spending program to improve its operating performance could be assessed negatively if its performance lags behind peers in the same regulatory jurisdiction.

What is your definition of regulatory jurisdiction?

A regulatory jurisdiction is defined as the area over which the regulator has oversight and could include single or multiple subsectors (water, gas, and power). A geographic region may have several regulatory jurisdictions. For example, the Office of Gas and Electricity Markets and the Water Services Regulation Authority in the U.K. are considered separate regulatory jurisdictions. In Ontario, Canada, the Ontario Energy Board represents a single jurisdiction with regulatory oversight for power and gas. Also, in Australia, the Australian Energy Regulator would be considered a single jurisdiction given that it is responsible for both electricity and gas transmission and distribution networks in the entire country, with the exception of Western Australia.

Are there examples of different preliminary regulatory advantage assessments in the same country or jurisdiction?

Yes. In Israel we rate a regulated integrated power utility and a regulated gas transmission system operator (TSO). The power utility's relationship with its regulator is extremely poor in our view, which led to significant cash flow volatility in a stress scenario (when terrorists blew up the gas pipeline that was then Israel's main source of natural gas, the utility was unable to negotiate compensation for expensive alternatives in its regulated tariffs). We view the gas TSO's relationship with its regulator as very supportive and stable. Because we already reflected this in very different preliminary regulatory advantage assessments, we did not modify the preliminary assessments because the two regulatory environments in Israel differ and were not the result of the companies' respective business strategies.

How is regulatory advantage assessed for utilities that are a natural monopoly but are not regulated by a regulator or a specific regulatory framework, and do you use the regulatory modifier if they achieve favorable treatment from the government as an owner?

The four regulatory pillars remain the same. On regulatory stability we look at the stability of the setup, with more emphasis on the historical track record and our expectations regarding future changes. In tariff-setting procedures and design we look at the utility's ability to fully recover operating costs, investments requirements, and debt-service obligations. In financial stability we look at the degree of flexibility in tariffs to counter volume risk or commodity risk. The flexibility can also relate to the level of indirect competition the utility faces. For example, while Nordic district heating companies operate under a natural monopoly, their tariff flexibility is partly restricted by customers' option to change to a different heating source if tariffs are significantly increased. Regulatory independence and insulation is mainly based on the perceived risk of political intervention to change the setup that could affect the utility's credit profile. Although political intervention tends to be mostly negative, in certain cases political ties due to state ownership might positively influence tariff determination. We believe that the four pillars effectively capture the benefits from the close relationship between the utility and the state as an owner; therefore, we do not foresee the use of the regulatory modifier.

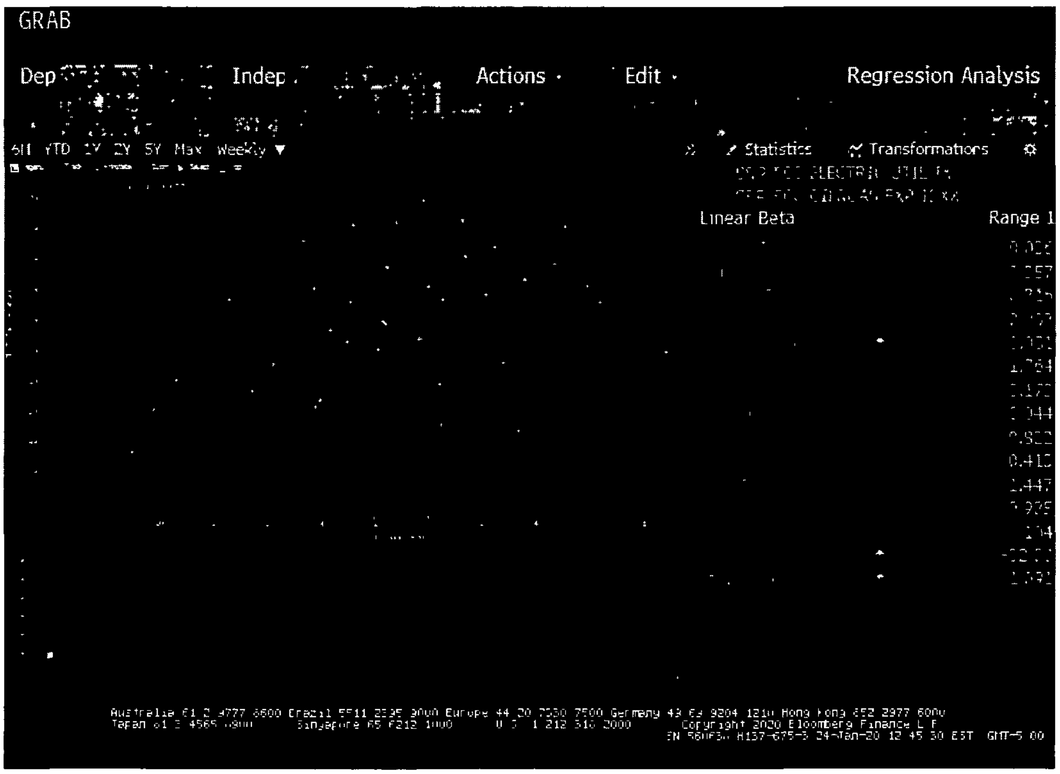
In table 1, when describing a "strong" regulatory advantage assessment, you mention that there is support of cash flows during construction of large projects, and preapproval of capital investment programs and large projects lowers the risk of subsequent disallowances of capital costs. Would this preclude a "strong" regulatory advantage assessment in jurisdictions where those practices are absent?

No. The table is guidance as to what we would typically expect from a regulatory framework that we would assess as "strong." We would expect some frameworks with no capital support during construction to receive a "strong" regulatory advantage assessment if in aggregate the other factors we analyze support that conclusion.

RELATED CRITERIA AND RESEARCH

- Corporate Methodology, Nov. 19, 2013
- Group Rating Methodology, Nov. 19, 2013
- Methodology: Industry Risk, Nov. 19, 2013
- Corporate Methodology: Ratios And Adjustments, Nov. 19, 2013
- Ratings Above The Sovereign--Corporate And Government Ratings: Methodology And Assumptions, Nov. 19, 2013
- Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Nov. 19, 2013
- Collateral Coverage And Issue Notching Rules For '1+' And '1' Recovery Ratings On Senior Bonds Secured By Utility Real Property, Feb. 14, 2013
- Methodology: Management And Governance Credit Factors For Corporate Entities and Insurers, Nov. 13, 2012
- General Criteria: Principles Of Credit Ratings, Feb. 16, 2011
- General Criteria: Rating Government-Related Entities: Methodology And Assumptions, Dec. 9, 2010

These criteria represent the specific application of fundamental principles that define credit risk and ratings opinions. Their use is determined by issuer- or issue-specific attributes as well as Standard & Poor's Ratings Services' assessment of the credit and, if applicable, structural risks for a given issuer or issue rating. Methodology and assumptions may change from time to time as a result of market and economic conditions, issuer- or issue-specific factors, or new empirical evidence that would affect our credit judgment.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Linear Beta
Range 1

SOAH DOCKET NO. 473-19-6862

PUC DOCKET NO. 49737

PUBLIC UTILITY COMMISSION OF TEXAS

APPLICATION OF

SOUTHWESTERN ELECTRIC POWER COMPANY

FOR CERTIFICATE OF CONVENIENCE AND NECESSITY

AUTHORIZATION AND RELATED RELIEF FOR

THE ACQUISITION OF WIND GENERATION FACILITIES

REBUTTAL TESTIMONY OF

JOHN O. AARON

FOR

SOUTHWESTERN ELECTRIC POWER COMPANY

FEBRUARY 12, 2020

TESTIMONY INDEX

SECTION PAGE

I. INTRODUCTION

Q. WOULD YOU PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS?

A. My name is John O. Aaron. I am Director, Regulated Pricing and Analysis in the Regulatory Services Department of American Electric Power Service Corporation (AEPSC). AEPSC is a subsidiary of American Electric Power Company, Inc. (AEP) that provides corporate support services to the operating subsidiaries of AEP, including Southwestern Electric Power Company (SWEPCO or the Company). My business address is 212 East Sixth Street, Tulsa, Oklahoma 74119-1295.

Q. ARE YOU THE SAME JOHN O. AARON WHO FILED DIRECT TESTIMONY IN THIS CASE?

A. Yes, I am.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to respond to East Texas Electric Cooperative, Inc. (ETEC) and Northeast Texas Electric Cooperative, Inc. (NTEC) witness James Daniel's criticisms of the Company's customer impact analysis and Texas Industrial Energy Consumers (TIEC) witness Jeffry Pollock's challenge to the Company's proposed deferred tax asset (DTA).

III. CUSTOMER IMPACT ANALYSIS

Q. HOW DO YOU RESPOND TO MR. DANIEL'S CLAIMS THAT SWEPCO HAS FAILED TO DEMONSTRATE THAT THIS PROPOSAL IS IN THE PUBLIC INTEREST (P.7) AND DOES NOT PROVIDE AN ACCURATE INDICATION OF CUSTOMER CLASS IMPACTS (P. 10-12)?

A. The Selected Wind Facilities (SWFs) are projected to create $764 million in nominal benefits for Texas retail customers. These benefits will result in a net decrease in rates for residential, commercial, and industrial customers. The average customer impact analysis provided in this proceeding is similar to the analysis provided by SWEPCO in its other Certificate of Convenience and Necessity (CCN) proceedings in Texas and in other general rate proceedings. There is no requirement to provide the customer impact analysis by rate class for various customer sizes or by base rates as recommended by Mr. Daniel, nor is such analysis typically provided in cases like this

Q. WHAT IS YOUR RESPONSE TO MR. DANIEL'S TESTIMONY REGARDING CLASS IMPACTS USING A DEMAND ALLOCATION FOR THE SWF COSTS AND AN ENERGY ALLOCATION FOR FUEL SAVINGS (P. 14-15)?

A. A demand allocation to customer classes of the costs of the SWFs does not reflect the basis for which SWEPCO is making this investment. The SWFs are not needed to meet SWEPCO's capacity requirements and do not result in capacity savings for SWEPCO until 2037. As discussed in my direct testimony, I used an energy allocator to illustrate customer impacts because an energy allocation matches the costs of the SWFs with the benefits generated by the SWFs and the production tax credits (PTCs) earned. For this reason, it is my opinion that an energy allocation is more appropriate than a demand allocation for the SWFs.

IV. DEFERRED TAX ASSET TREATMENT

Q. DO YOU AGREE WITH MR. POLLOCK'S CLAIMS THAT THE PROPOSED DTA IMPROPERLY FORCES CUSTOMERS TO FINANCE PTCs SWEPCO CANNOT MONETIZE (P. 33)?

A. No, I do not. SWEPCO's request in this case to recover carrying costs on the DTA in a future rider and in future base rate case filings is appropriate and proper rate making treatment given the up-front benefits that the PTCs generated by the SWFs provide to SWEPCO's customers. SWEPCO's customers receive the benefits of the PTCs as they are earned by SWEPCO via lower tax expense (*i.e.*, up-front benefit), not when SWEPCO is subsequently able to use the PTCs to offset its regular tax liability. The DTA's carrying costs compensate SWEPCO for its cost of providing the up-front tax expense benefit to customers before the Company is able to use the PTCs to offset its tax liability. This treatment is conceptually no different than the treatment of deferred tax liabilities that reduce SWEPCO's rate base in a general base rate proceeding. In that situation, a customer is provided a carrying cost associated with accumulated deferred income tax (ADIT) liabilities because the customer is providing current funds (*i.e.*, benefit) to SWEPCO for taxes that SWEPCO will pay in the future. A DTA is simply a deferred tax asset that increases rate base, while ADIT is a deferred tax liability that decreases rate base. In both cases (deferred tax asset and deferred tax liability), one party is providing a tax-related benefit to the other before it actually receives that benefit and is compensated by receiving a carrying cost. Thus, the Company's DTA-related proposals in this proceeding are reasonable, consistent with the Commission's typical treatment of deferred taxes, and appropriate.

Q. IS THE SIZE OF THE DTA RELATED TO ADIT ATTRIBUTABLE TO THE SELECTED WIND FACILITIES?

A. Yes. Customers benefit from the five-year accelerated tax depreciation of the SWFs. This results in a large rate base reduction through the ADIT liability that will be recorded for the excess of tax depreciation over book depreciation which is based on a thirty-year life. This high level of tax depreciation also results in a large reduction in taxable income in the first few years of the facilities' lives, which reduces SWEPCO's tax "appetite" (*i.e.*, the ability to use the PTCs in the year earned - which is a significant contributing factor to the existence and size of the DTA). As a result, the existence of the DTA is, in part, a result of the ADIT benefits created by the SWFs and received by customers, and should not be viewed in isolation.

Q. WHAT ARE THE CUSTOMERS' COMBINED TAX BENEFITS AND COSTS OF THE SELECTED WIND FACILITIES?

A. SWEPCO Texas customers receive total tax benefits of approximately $309 million from the SWFs, as shown below.

SWEPCO Texas Jurisdictional Tax Related (Benefits) / Costs for SWF 30 Year Life		
DTA Carrying Cost	$	80,987,674
Income Tax (exclude PTC)		71,337,333
ADIT (Benefit)		(104,188,418)
PTC (Benefit)		(357,079,976)
Net Benefit	$	(308,943,387)

V. CONCLUSION

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.